SPECIFIED GAS EMITTERS REGULATION

TECHNICAL GUIDANCE FOR COMPLETING BASELINE EMISSIONS INTENSITY APPLICATIONS

JANUARY 2009

Version 2.0

Alberta

ALBERTANS & CLIMATE CHANGE

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The information provided in this document is intended as guidance only. This document is not a substitute for the law. Please consult the *Specified Gas Emitters Regulation* and the legislation for all purposes of interpreting and applying the law. In the event that there is a difference between this document and the *Specified Gas Emitters Regulation* or legislation, the *Specified Gas Emitters Regulation* or the legislation prevail.

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Abbreviations

AENV	Alberta Environment
BEI	Baseline Emissions Intensity
CCEMA	Climate Change and Emissions Management Act
CCEMF	Climate Change and Emissions Management Fund
CH_4	Methane
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
DUNS	Data Universal Numbering System
EI	Emissions Intensity
EPEA	*Environmental Protection and Enhancement Act*
EUB	Energy and Utilities Board
ERCB	Energy Resources Conservation Board
GJ	Gigajoule
GWP	Global Warming Potential
h	Hour
HFC	Hydrofluorocarbons
HHV	Higher Heating Value
IP	Industrial Process Emissions
kg	Kilogram
kJ	Kilojoule
kt	Kilotonne
LHV	Lower Heating Value
MWh	Megawatt-hour
N_2O	Nitrous Oxide
N/A	Not Applicable
NAICS	North American Industry Classification System
NEI	Net Emissions Intensity
NEIL	Net Emissions Intensity Limit
NGCC	Natural Gas Combined Cycle
NPRI	National Pollutant Release Inventory
P	Production
PFC	Perfluorocarbons
SF_6	Sulphur Hexafluoride
SGER	Specified Gas Emitters Regulation
SoC	Statement of Certification
SoQ	Statement of Qualification
SoV	Statement of Verification

TDE	Total Direct Emissions
TAE	Total Annual Emissions
t	Tonnes

Related AENV Publications

- Climate Change and Emissions Management Act
- Specified Gas Emitters Regulation
- Specified Gas Reporting Regulation

- Alberta's 2008 Climate Change Strategy

- Technical Guidance for Completing Annual Compliance Reports
- Technical Guidance for Completing Baseline Emissions Intensity Applications
- Additional Guidance for Cogeneration Facilities
- Technical Guidance for Landfill Operators

- Offset Credit Project Guidance Document
- Offset Credit Verification Guidance Document

SGER Forms

- Baseline Emissions Intensity Application for Existing Facility
- Baseline Emissions Intensity Application for New Facility
- Baseline Emissions Intensity Application for Existing Stand-alone Cogeneration Facility
- Baseline Emissions Intensity Application for New Stand-alone Cogeneration Facility

- 2008 Compliance Report Form
- 2008 Compliance Report Form for Stand-Along Cogeneration Facilities

- Landfill without gas collection
- Landfill with partial gas collection
- Landfill with gas collection

Glossary of Terms

Act means the *Climate Change and Emissions Management Act* (CCEMA)

Baseline Emissions Intensity (BEI) for established facilities is the average of that facility's direct emissions intensity for 2003, 2004 and 2005. For new facilities, the BEI is based on the third year of commercial operation. These definitions are in accordance with Part 4 of the *Specified Gas Emitters Regulation*.

Biomass refers to material derived from living or recently dead organisms. Examples include but are not limited to: wood and wood products, charcoal, agricultural residue, landfill gas and bio-alcohols. A more complete list is available in section 4.1.9 of this document.

Biomass emissions are direct emissions resulting from the decomposition and/or combustion of biomass from plant materials and animal waste

Certifying Official is the person designated by the facility with signing authority for that facility.

Climate Change and Emissions Management Act is the enabling legislation passed in 2002 allowing Alberta Environment to manage greenhouse gas emissions in the province.

Climate Change and Emissions Management Fund is the fund set up under the Climate Change and Emissions Management Act that will be used to support research, development and deployment of transformative change technologies to reduce greenhouse gas emissions in Alberta.

CO_2e is the 100-year global warming potential average of a unit of greenhouse gas (e.g. methane) compared to an equivalent unit of carbon dioxide (reference gas).

Direct emissions means the release of greenhouse gases expressed as tonnes CO_2e from all sources located at a facility.

Director is Alberta Environment's representative appointed under the *Specified Gas Emitters Regulation* and who is charged with implementing the *Regulation*.

Emission offset is a reduction in one or more specified gases (regulated greenhouse gas emissions) occurring at sites not covered by the *Specified Gas Emitters Regulation*. Additional information on Offsets is available at: http://environment.alberta.ca/1238.html.

Emission Performance Credits (EPC) are generated when a facility reduces its Net Emissions Intensity below its Net Emissions Intensity Limit. EPCs are awarded on a tonne CO_2e reduction basis

Established facility is a facility that completed its first year of commercial operation on or before January 1, 2000, or that has completed eight consecutive years of commercial operation.

Facility is any plant, structure or thing that sits on one or more contiguous or adjacent sites that are operated and function in an integrated fashion and includes all buildings, equipment, structures, machinery and vehicles that are an integral part of the activity.

Flaring emissions are direct emissions from the controlled combustion of a gas or liquid stream produced on site for purposes other than producing energy. This includes but is not limited to the incineration of waste petroleum and other hazardous materials, safety flares, and test wells.

Fund Payment is a compliance payment made in to the Climate Change and Emissions Management Fund.

Global Warming Potential (GWP) measures a greenhouse gas's relative warming effect on the earth's atmosphere compared with carbon dioxide and is expressed as a 100-year average. Alberta accepts the Intergovernmental Panel on Climate Change's warming potentials for the gases regulated under the *Specified Gas Emitters Regulation.*

HFC Species are hydroflurocarbon gases and include: CHF_3, CH_2F_2, CH_3F, $C_5H_2F_{10}$ (structure: $CF_3CHFCHFCF_2CF_3$), C_2HF_5, $C_2H_2F_4$ (structure: CHF_2CHF_2), $C_2H_2F_4$ (structure: CH_2FCF_3), $C_2H_3F_3$ (structure: CHF_2CH_2F), $C_2H_3F_3$ (structure: CF_3CH_3), $C_2H_4F_2$ (structure: CH_3CHF_2), C_3HF_7 (structure: CF_3CHFCF_3), $C_3H_2F_6$ (structure: $CF_3CH_2CF_3$) and $C_3H_3F_5$ (structure: $CH_2FCF_2CHF_2$). These gases are regulated under the *Specified Gas Emitters Regulation.*

Industrial process emissions are direct emissions from sources directly associated with production that involve chemical or physical reactions, other than combustion, and where the primary purpose of the process is not energy production.

Industrial product use emissions are all direct emissions from the use of HFCs, PFCs or SF_6 associated with production that do not meet the definition of Industrial Process Emissions. Examples include SF_6 and HFC use as a cover gas and SF_6 in on-site electrical equipment.

Net Emissions Intensity (NEI) is the facility's Total Annual Emissions minus true-up options used (Offsets, EPCs, or Fund Contributions) divided by the facility's total annual production expressed in appropriate units.

Net Emissions Intensity Limit (NEIL) is the facility's maximum net emissions intensity permitted under section 4 of the *Specified Gas Emitters Regulation.* This limit is set at 88 per cent of the baseline emissions intensity for existing facilities. New facilities are phased in at a rate of 2 per cent per year starting in their fourth year of commercial operation.

New facility is a facility that completed its first year of commercial operation on or after December 31, 2000 and has completed less than eight years of commercial operation.

On-site transportation emissions are direct emissions resulting from fuel combustion in machinery used for the on-site transportation of products and material including raw, intermediate and end products.

Other fugitive emissions are direct emissions that do not fall under the other emissions categories and includes without limitation, intentional or unintentional releases of gases arising from the production, processing, transmission, storage and use of solid, liquid or gaseous fuels.

Person Responsible is the person legally responsible for the operations of the facility. This person is the approval or registration holder for a facility regulated under the *Environmental Protection and Enhancement Act* or the legal owner for facilities not subject to EPEA approval.

PFC species are perflurocarbons gases and include: CF_4, C_2F_6, C_3F_8, C_4F_{10}, c-C_4F_8, C_5F_{12}, and C_6F_{14}. These gases are subject to the *Specified Gas Emitters Regulation*.

Production is the total quantity of end product(s) produced by a facility. If a facility does not have an end product, the Director under the *Specified Gas Emitters Regulation* may specify an input, throughput or other thing as a production metric.

Regulation means the *Specified Gas Emitters Regulation*.

Reporter is the person designated by the facility responsible for completing the facility's Baseline Emissions Intensity Application form.

Specified gases are the six greenhouse gas species—carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), PFCs, HFCs, and sulphur hexafluoride (SF_6)—regulated under the *Climate Change and Emissions Management Act* and the *Specified Gas Emitters Regulation*.

Stationary fuel combustion emissions are direct emissions from the combustion of fossil or biomass fuel for the purpose of producing energy excluding CO_2 emissions from the combustion of biomass.

Total Annual Emissions (TAE) are the total direct emissions not including industrial process emissions, CO_2 emissions from combustion of biomass and CO_2 emissions from decomposition of biomass waste emitted by a facility in a calendar year.

Total Direct Emissions (TDE) is the release of all specified gases expressed in tonnes CO_2e from all sources located at a facility.

Third Party Verifier is a professional engineer or chartered account qualified to conduct an independent, third party review of the facility's baseline application before it is submitted to Alberta Environment.

Unit of production is an appropriate common production metric for all end products of a facility consistent with the industry accepted norms for the sector to which the facility belongs.

Formation CO2 emissions are direct, gaseous emissions of carbon dioxide recovered or recoverable at a well from an underground reservoir including, but not limited to, CO_2 emissions vented from gas sweetening and formation gas.

Venting emissions are direct emissions from the intentional release to the atmosphere of waste gas or liquid streams.

Waste and wastewater emissions means direct emissions from disposal or treatment of waste or wastewater, but does not include CO_2 emissions from decomposition of biomass waste.

Year is calendar year.

1.0 Purpose of this document

The purpose of this document is to assist regulated facilities under the *Specified Gas Emitters Regulation* with the completion of the Baseline Emissions Intensity Applications.

A facility's stated baseline value must be representative of the facility's normal operating conditions. If the baseline period is not representative of that facility's standard operating conditions, the Certifying Official must contact Alberta Environment to discuss an adjusted baseline period. More information on alternate baselines is available in section 3.2 of this guidance document.

Alberta Environment recognizes that changes in operation at a facility may require the facility to restate its baseline. Examples include, but are not limited to, detection of errors, improvements in reporting methodology, changes in emissions or production, changes in production technology, expansions, and decommissioning. Procedures for re-establishing a baseline are discussed in section 3.3.

Facilities that do not meet the regulatory threshold, but that still wish to report their greenhouse gas emissions may do so under the *Specified Gas Reporting Program*. More information on this program is available on the Alberta Environment Greenhouse Gas Reporting website at: http://environment.alberta.ca/2881.html. These facilities are also eligible to generate Emissions Offsets. More information on Alberta's Offset system is available at: http://environment.alberta.ca/1238.html.

1.1 Overview of Changes

The Technical Guidance for Completing Baseline Emissions Intensity Applications has been up-dated following the completion of the first compliance period. We have provided greater clarity around key issues that came up during the review of the Baseline Emissions Intensity Applications. We have also responded to feedback received during the June 10 and 12, 2008 stakeholder sessions, and the November 19 and 20 program update sessions.

Changes include:

- Providing clarification on the policy intent of the Specified Gas Emitters program;
- Providing clarification on triggers that may require a facility to use an alternate baseline;
- Providing clarification on the signing requirements for the Statement of Qualifications, Statement of Verification, and Conflict of Interest;
- Providing examples of industrial process emissions;
- The vented Raw Gas source category was renamed Formation CO_2 to reflect actual emissions reported in this category;

- The CO_2 emissions from Aerobic Decomposition of Waste source category was renamed CO_2 Emissions from Decomposition of Waste to allow reporting of CO_2 emissions from aerobic and anaerobic decomposition of waste in this source category;
- Discuss Alberta Environment's Cogeneration Policy Review and provide guidance for 2008 baseline applications that include cogeneration; and
- Provide information on Alberta Environment's Specified Gas Emitters program audits.

Alberta Environment has initiated policy reviews on some of the issues identified in the 2007 program review. On-going policy review processes include:

- Considering Refinery Activity Index (RAI) as a denominator metric;
- Considering Inlet Gas as a denominator metric;
- Cogeneration Policy Review;
- Expansion treatment for facilities; and
- Decommissioning of facilities.

2.0 Specified Gas Emitters Program

In 2002, Alberta passed the *Climate Change and Emissions Management Act* signalling its commitment to manage climate change and greenhouse gas emissions in the province. In 2003, Alberta passed the *Specified Gas Reporting Regulation* requiring all facilities emitting over 100,000 tonnes of carbon dioxide equivalent (CO_2e) annually to report their emissions.

In 2007, Alberta passed the *Specified Gas Emitters Regulation* (SGER) reinforcing its commitment to regulate greenhouse gas emissions from large industrial emitters. This regulation (the *Regulation*) requires all facilities in Alberta emitting over 100,000 tonnes of CO_2e per year to reduce their emissions intensity by 12 per cent below their 2003-2005 baseline emissions intensity. New facilities, or those facilities that began operation on or after January 1, 2000 and that have completed less than 8 years of commercial operation, have been given a graduated reduction obligation increasing 2 per cent per year starting in their fourth year of commercial operations up to a reduction obligation of 12 per cent.

Greenhouse gas emissions intensity is regulated on a facility-by-facility basis. That is, targets are set at the facility and that facility's performance over time is compared against its approved baseline emissions intensity. Alberta Environment supports and encourages consistency in reporting methodologies across individual sectors. Where appropriate, sectors are encouraged to develop sector specific reporting methodologies that improve accuracy and reporting of greenhouse gas emissions for that sector.

The *Regulation* encourages facilities to improve their emissions performance relative to production. This can be achieved through a combination of initiatives including incremental improvements in energy use on site, development of Emission Offset projects, and supporting development and implementation of new emissions reduction technologies.

2.1 Thresholds

The threshold for compliance under the *Specified Gas Emitters Regulation* has been set at 100,000 tonnes of carbon dioxide equivalent (CO_2e) per year for all greenhouse gas emissions from all sources. These total direct emissions (TDE) include emissions from biomass and industrial processes. Facilities that exceed this threshold in any single calendar year on or after 2003 must establish an emissions intensity baseline for the facility and submit annual compliance reports.

2.2 Reduction Obligations

Annual emissions intensity reduction obligation

The *Specified Gas Emitters Regulation* requires all facilities emitting over 100,000 tonnes of CO_2e per year to reduce their annual emissions intensity by 12 per cent below their

approved Baseline Emissions Intensity (BEI). This is known as the facility's Net Emissions Intensity Limit (NEIL).

Established facilities are those facilities that completed their first year of commercial operation on or before January 1, 2000, or that have completed eight or more years of commercial operation. Established facilities have a 12 per cent reduction obligation off their BEI.

New facilities are those facilities that completed their first year of commercial operation on or after December 31, 2000 and have completed less than eight years of commercial operation. The BEI for a new facility is established based on the facility's third year of commercial operation. Emission intensity reductions for these facilities will be phased in over a 6-year period at rate of 2 per cent per year beginning in the facility's forth year of operation.

Net Emissions Intensity Limit for New Facilities		
Start-up	Grace period for initial operations	No target
Year1	First full calendar year of commercial operation	No target
Year 2	Second year of commercial operation	No target
Year 3	Establish baseline	Baseline
Year 4	First year reduction obligation	2% target
Year 5	Second year reduction obligation	4 % target
Year 6	Third year reduction obligation	6 % target
Year 7	Fourth year reduction obligation	8 % target
Year 8	Fifth year reduction obligation	10 % target
Year 9	Considered an established facility	12 % target

Table 1: New Facility reduction obligation based on the number of years of commercial operation.

Options to meet emissions intensity reduction targets

Compliance with the NEIL reduction obligation is calculated on a per tonne of carbon dioxide equivalent basis. If a facility is not able to meet its reduction obligation through facility improvements such as technology improvements, changes in maintenance, adding new technologies, etc., the facility may use any one or more of the following three compliance options:

1. Emissions Performance Credits: use banked Emissions Performance Credits (EPCs) generated in previous compliance periods where the facility beat its emissions reduction target, or purchase EPCs from a different regulated facility that has reduced its emissions below its net emissions intensity limit.

2. Alberta-based Offsets: purchase Emission Offset Credits generated from an Alberta-based offsets project that uses a government-approved protocol.
3. Climate Change and Emissions Management Fund Contribution: Fund contributions are made at a cost of $15 per tonne of CO_2e to a maximum of the facility's compliance obligations

If a facility's annual emission intensity is over its NEIL, the facility must obtain sufficient credits such that the effective CO_2e emissions for the facility equal its intensity limit. The facility may purchase valid Offset Credits, Emissions Performance Credits or make a contribution to the Climate Change and Emissions Management Fund.

If a facility reduced its emissions intensity below its NEIL, the facility is eligible for Emission Performance Credits (EPC). These credits can be banked, or traded to other Alberta facilities that have not met their emissions reduction target. EPC credits must be serialized through Alberta Environment before they can be used as a compliance option. More information on these compliance options is available in section 3.2 of the Technical Guidance for Completing Specified Gas Compliance Reports.

3.0 Baseline Application Process

The baseline emissions intensity for a facility is established to represent normal operating conditions at the facility. This facility's annual emissions intensity is compared against this baseline to determine if the facility has met its NEIL. If the 2003-2005 baseline is not representative of normal operating conditions and is not appropriate for a facility, the Certifying Official must contact Alberta Environment to discuss alternate baseline years that are more representative of the facility's normal operating conditions.

Alberta Environment recognizes that situations may arise where the operating conditions of the facility change. If this occurs, the Certifying Official should contact Alberta Environment to discuss whether a change in the baseline is needed.

3.1 Process for Assessing Coverage under the SGER

The following is a guide to determine whether a facility is covered by the *Specified Gas Emitters Regulation.* More detailed, sheet-by-sheet instructions for completing a baseline application are available in Appendix A.

1. Determine if the facility's total direct emissions including biomass and industrial process emissions were equal to or greater than 100,000 tonnes CO_2e in any single calendar year starting in 2003.
    - If the facility's emissions are below the 100,000 CO_2e threshold in all years since 2003, the facility is not subject to the *Regulation.* Facilities not subject to the *Regulation* are eligible to participate in the Emissions Offset program.
    - If the facility exceeded 100,000 tonnes CO_2e in any single year on or after 2003, the facility is subject to the *Regulation* and must submit a Baseline Emissions Intensity Application.

2. Determine the facility's baseline emission intensity:
    - If the facility completed its first year of commercial operation before January 1, 2000, or has completed eight or more years of operation, it is considered an established facility. The facility must establish a baseline based on the average emissions intensity for the years 2003-2005.
    - If the facility completed its first year of commercial operation on or after December 31, 2000 and has completed less than eight years of commercial operation, or if the facility is designated as a new facility under subsection (2) of the *Regulation*, it is considered a new facility. New facilities must establish a baseline based on the third year of commercial operation.
    - New facilities that exceed eight years of commercial operation must continue to report against their approved baseline (third year of commercial operation).

3. Complete the appropriate Baseline Emissions Intensity Application form available on Alberta Environment's website (http://environment.alberta.ca/631.html). Baseline Application forms are provided for:
    - Established facilities,
    - New facilities,
    - Established stand-alone cogeneration facilities, and
    - New stand-alone cogeneration facilities.

4. Facilities that have tripped the reporting threshold must submit a Baseline Emissions Intensity Applications by June 1 of the year following the year they tripped the compliance threshold.
    - For example, if a facility trips the 100,000 tonne threshold in 2008, it must submit the appropriate baseline emissions intensity application by June 1, 2009. The facility must then submit annual compliance reports starting in 2009 (due March 31, 2010).

    If a facility wishes to re-establish a Baseline Emissions Intensity, it must contact Alberta Environment to receive the appropriate application form. All requests for alternate and re-established baselines must be received by June 1 of the compliance period for which the new baseline intensity will be applied. For example, a facility wishing to change its baseline for the 2010 compliance year must have submitted the proposed baseline adjustments by June 1, 2010 based on the 2009 full year data. The compliance report due March 31st, 2011 would then use this new baseline, if approved.

5. The following documents **must** be included in the facility's baseline application:
    - Third Party verified Baseline Emissions Intensity Application form (Electronic)
    - Third Party Verifier's Report (Electronic)
    - Simplified process flow diagram
    - The signed **original** Conflict-of-Interest Checklist,
    - The signed **original** Statement of Certification form,
    - The signed **original** Statement of Qualification form,
    - The signed **original** Statement of Verification form, and
    - If required, a Confidentiality Request and supporting documentation

    Alberta Environment encourages the Reporter to include additional supporting documents including detailed emissions calculations, supporting data, emissions calculation methodologies, etc. with their application. Sufficient information should be supplied to allow AENV to understand the facility's application form. AENV may request additional information if needed to determine completeness Providing sufficient supporting materials and details initially can reduce processing time required to review the facility's submission. .

All baseline applications must be third party verified to ensure accuracy of the submission. More information on verification is available in section 8.0 of this guidance document.

Electronic signatures are not permissible under the Specified Gas Emitters program.

The *Regulation* also requires the Third Party Verifier to be an individual. If a company wishes to sign on behalf of a corporation, sign-off may be done as:

Company Name
Per [Corporate Signing Officials]

All documents listed above must be submitted to Alberta Environment with original signatures from a designated authority or the submission may be deemed incomplete.

For administrative purposes, e-mail submissions sent to **AENV.GHG@gov.ab.ca** must be for a single facility only.

Submissions sent by courier (CD/DVD) may contain applications for one or more facilities; however, each facility application must be clearly identified for accurate tracking and filing by Alberta Environment. CD/DVDs and hardcopies of supporting documents must be submitted to:

Director
Alberta Environment
12th Floor, 10025 – 106 Street
Edmonton, Alberta
T5J 1G4

An e-mail confirming receipt of the baseline application will be sent to the Reporter and Certifying Official upon receipt of the application package.

If a facility is requesting confidentiality for part of its compliance submission, the request, along with justification and supporting documentation, must be submitted by mail or courier to Alberta Environment no later than the June 1 baseline application deadline. The Director will issue a decision in writing within 150 days of the receipt of the Request for Confidentiality.

6. Once Alberta Environment has received the Baseline Application and supporting documents, the Director will review the application and inform the Person Responsible in writing that:
   - The baseline emissions intensity for the facility has been accepted, **or**
   - The Director has prescribed a baseline emissions intensity for the facility.

If a request for confidentiality has been submitted, the facility will receive notification of the Director's decision within 150 days of the receipt of the confidentiality request letter. Figure 1 below outlines the baseline application process. Confidentiality is discussed in more detail in section 7.0.

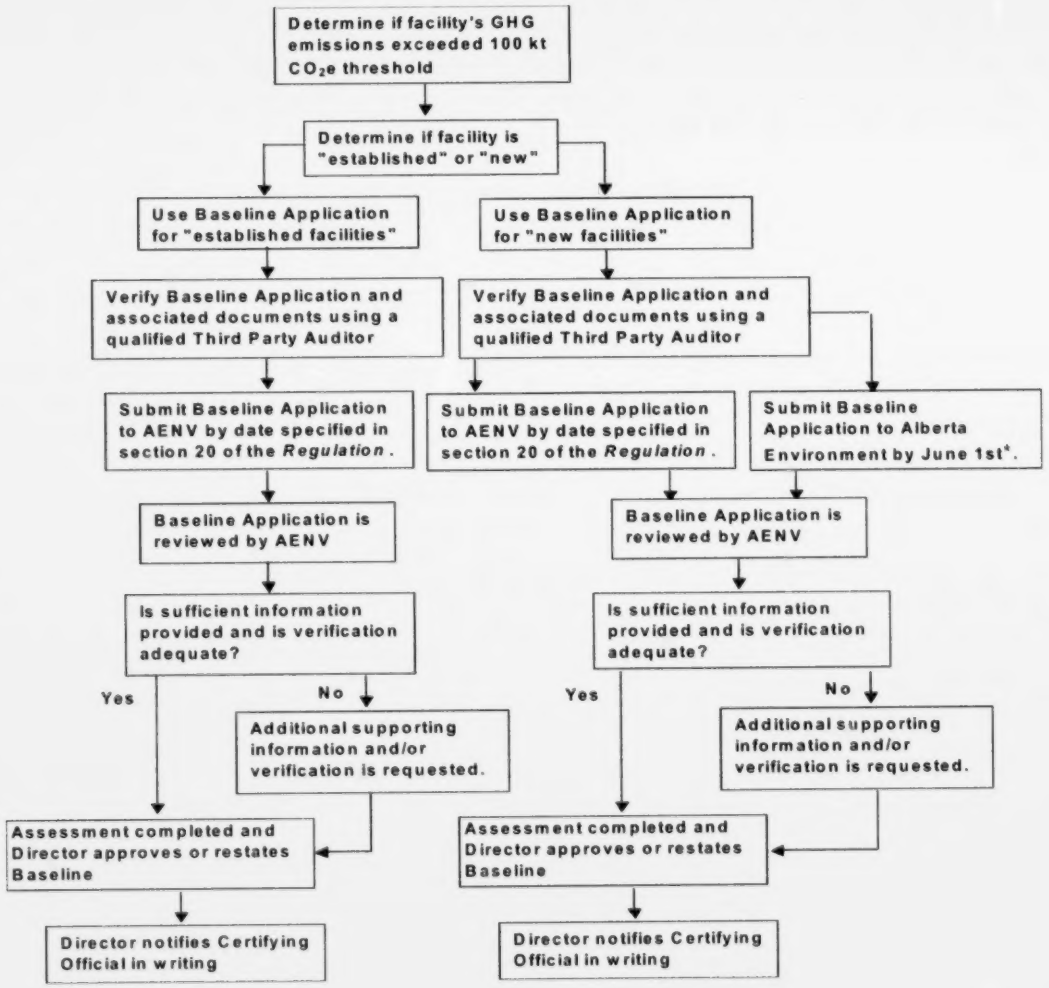
Determine if facility's GHG emissions exceeded 100 kt CO_2e threshold
Determine if facility is "established" or "new"
Use Baseline Application for "established facilities"
Use Baseline Application for "new facilities"
Verify Baseline Application and associated documents using a qualified Third Party Auditor
Verify Baseline Application and associated documents using a qualified Third Party Auditor
Submit Baseline Application to AENV by date specified in section 20 of the *Regulation*.
Submit Baseline Application to AENV by date specified in section 20 of the *Regulation*.
Submit Baseline Application to Alberta Environment by June 1st[4].
Baseline Application is reviewed by AENV
Baseline Application is reviewed by AENV
Is sufficient information provided and is verification adequate?
Is sufficient information provided and is verification adequate?
Yes
No
Yes
No
Additional supporting information and/or verification is requested.
Additional supporting information and/or verification is requested.
Assessment completed and Director approves or restates Baseline
Assessment completed and Director approves or restates Baseline
Director notifies Certifying Official in writing
Director notifies Certifying Official in writing

Figure 1: Baseline Application Process for the Specified Gas Emitters Program.

3.2 *Alternate Baseline Applications*

A facility's baseline must be representative of its normal operating conditions. However, events may occur that cause the 2003-2005 baseline to be inappropriate for some facilities. Examples include:

- Where the market is depressed and the facility is operating below capacity;

- Major interruption in production occurs resulting in the facility being shutdown for an extended period of time during the baseline period.
- The facility undergoes expansion resulting in changes in operation during the baseline period.

If the Certifying Official feels the baseline period is not appropriate for their facility, they should contact Alberta Environment to discuss an alternate, more representative baseline period. If both parties agree that a different baseline period is more appropriate for that facility, AENV will provide the facility with an Alternate Baseline Application form.

The baseline application forms provided by Alberta Environment are prescribed forms and cannot be altered. If different forms are needed, Alberta Environment will provide these forms. Forms that have been altered by a facility will not be accepted for compliance under the *Specified Gas Emitters Regulation.*

Alberta Environment recognizes that situations may arise where a facility will need to re-establish its baseline emissions intensity. We are working to develop policy guidance around triggers for re-establishing baselines, including decommissioning of facilities. Until such time as the guidance is available, facilities that have undergone significant change or that are moving into a decommissioning phase should contact Alberta Environment to discuss an appropriate path forward.

4.0 Estimation and Reporting of Specified Gases

The *Specified Gas Emitters Regulation* applies to any facility that releases 100,000 tonnes or more of CO_2e based on the sum of direct emissions of carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFC), perfluorocarbons (PFC), and sulphur hexafluoride (SF_6). Table 2 provides a list of the specified gases (greenhouse gases) subject to the *Regulation* including their 100-year global warming potential used to calculate CO_2e emissions.

Specified Gas	Formula	100-year GWP
Carbon dioxide	CO_2	1
Methane	CH_4	21
Nitrous Oxide	N_2O	310
Sulphur Hexafluoride	SF_6	23900
Perfluorocarbons (PFC)		
Perfluoromethane	CF_4	6500
Perfluoroethane	C_2F_6	9200
Perfluoropropane	C_3F_8	7000
Perfluorobutane	C_4F_{10}	7000
Perfluorocyclobutane	c-C_4F_8	8700
Perfluoropentane	C_5F_{12}	7500
Perfluorohexane	C_6F_{14}	7400
Hydrofluorocarbons (HFC)		
HFC-23	CHF_3	11700
HFC-32	CH_2F_2	650
HFC-41	CH_3F	150
HFC-43-10mee	$C_5H_2F_{10}$ (structure: $CF_3CHFCHFCF_2CF_3$)	1300
HFC-125	C_2HF_5	2800
HFC-134	$C_2H_2F_4$ (structure: CHF_2CHF_2)	1000
HFC-134a	$C_2H_2F_4$ (structure: CH_2FCF_3)	1300
HFC-143	$C_2H_3F_3$ (structure: CHF_2CH_2F)	300
HFC-143a	$C_2H_3F_3$ (structure: CF_3CH_3)	3800
HFC-152a	$C_2H_4F_2$ (structure: CH_3CHF_2)	140
HFC-227ea	C_3HF_7 (structure: CF_3CHFCF_3)	2900
HFC-236fa	$C_3H_2F_6$ (structure: $CF_3CH_2CF_3$)	6300
HFC-245ca	$C_3H_3F_5$ (structure: $CH_2FCF_2CHF_2$)	560

Table 2: Specified Gases and Gas Species Subject to the Regulation.

4.1 Emissions Source Categories

Source categories have been established to facilitate reporting of specified gas emissions in all categories and the treatment of excluded emissions from certain categories. Details on the treatment of emissions from each category are provided in sections 4.1.1 through 4.1.10 below.

Emissions of CO_2, CH_4, N_2O, HFC, PFC, and SF_6 must be disaggregated and reported according to the following source categories:

- Stationary Fuel Combustion
- Industrial Process
- Venting
- Flaring
- Other Fugitive
- On-site Transportation
- Waste and Wastewater
- Formation CO_2
- CO_2 Emissions from the Combustion of Biomass
- CO_2 Emissions from the Decomposition of Biomass

Table 3 provides a general overview of relevant emissions per source category and their treatment in determining whether the facility has triggered the regulatory threshold. Industrial process emissions and CO_2 emissions from biomass are included in calculating the facility's threshold emissions, but are not included in the facility's baseline emissions calculations as described below.

Source Category	Specified Gas	Reported	Threshold (TDE)	Baseline (TAE)
Stationary Fuel Combustion (Includes CH_4 and N_2O emissions from the combustion of biomass)	CO_2, CH_4, N_2O	✓	✓	✓
Industrial Process	All	✓	✓	×
Venting (Does not include Formation CO2)	CO_2, CH_4, N_2O	✓	✓	✓
Flaring (Does not include flaring of landfill gas)	CO_2, CH_4, N_2O	✓	✓	✓
Other Fugitive	CO_2, CH_4, N_2O	✓	✓	✓
Formation CO_2	CO_2	✓	✓	✓
Waste and Wastewater (Includes emissions from incineration of non-biomass waste and CH_4 & N_2O emissions from decomposition of waste and CH_4 & N_2O emissions from flaring of landfill gas)	CO_2, CH_4, N_2O	✓	✓	✓
On-site Transportation	CO_2, CH_4, N_2O	✓	✓	✓
CO_2 Emissions from the Combustion	CO_2	✓	✓	×

of Biomass (Includes CO_2 emissions from combustion of biomass, incineration of waste biomass and flaring of landfill gas)				
CO_2 Emissions from the Decomposition of Biomass	CO_2	✓	✓	×

Table 3: Summary of Reporting Requirements by Source Category and Specified Gas.

4.1.1 Stationary Fuel Combustion

Stationary fuel combustion emissions are direct emissions resulting from non-vehicular combustion of fossil or biomass fuel (CO_2 emissions from biomass combustion are exempt but NO_2 and CH_4 emissions must be reported) at the facility for the purpose of energy production (i.e. to generate electricity, heat or steam). These emissions are a common source of greenhouse gas emissions and are produced in most industrial sectors. The stationary fuel combustion source category includes on-site waste incineration if the waste is combusted for the purpose of energy production. Emissions from waste incineration when used as a disposal method must be included in the Waste and Wastewater source category.

CO_2 emissions from the combustion of biomass must be reported in a separate source category (CO_2 Emissions from the Combustion of Biomass) and included in the calculation of the emissions threshold (TDE), but are not included in the calculation of total annual emissions (TAE) for the facility or the facility's compliance obligation. N_2O and CH_4 emissions from biomass combustion must be reported in the Stationary Fuel Combustion source category and included in the total annual emissions (TAE) emissions.

4.1.2 Industrial Process

Industrial process emissions are direct emissions from an industrial process involving chemical or physical reactions, other than combustion, and where the primary purpose of the industrial process is not energy production. This includes mineral, metal and chemical production. This source category is sector-specific and is not found in all industrial sectors.

Where industrial process emissions are produced in combination with emissions from fuel combustion for energy purposes, the emissions must be included in the source category for the primary purpose of the activity. For example, if the primary purpose of the activity is generating energy, then the emissions must be included in the Stationary Fuel Combustion source category.

Industrial Process emissions are included in the facility's threshold emissions calculation, but are excluded from the facility's total annual emissions calculation. Alberta Environment is reviewing the treatment of Industrial Process emissions. These emissions

may be assigned a zero (0) per cent reduction obligation starting in the 2009 compliance period.

The following list contains examples of Industrial Process emissions that have been approved by Alberta Environment:

- CO_2 from steam methane reforming for various uses including ammonia production
  - $CH_4 + 2H_2O \longrightarrow 4H_2 + CO_2$
- CO_2 calcination of lime stone for clinker production and quick lime production
  - $CaCO_3 \longrightarrow CaO + CO_2$
- CO_2 liberated from phosphate bearing rock exposed to acids during phosphoric acid production
- Entrained CO_2 from ethylene facility feedstock
- N_2O from nitric acid combuster

If a facility is unclear whether an emissions source is classified as industrial process, they must discuss it with Alberta Environment before submitting their baseline application.

4.1.3 Venting

Vented emissions are direct emissions from intentional releases to the atmosphere of a waste gas or liquid stream and including, but not limited to: emissions of casing gas, treater, stabilizer, dehydrator off-gas, blanket gas and emissions from pneumatic devices, which use natural gas as a driver, compressor start-up, pipeline and other blowdowns and metering and regulation station control loops. Formation CO_2 emissions are not included in this source category.

4.1.4 Flaring

Flaring emissions are direct emissions from the controlled combustion of a gas or liquid stream produced on site, but not for the purpose of energy production and include, without limitation, emissions arising from waste petroleum incineration, hazardous emissions prevention systems (whether in pilot or active mode), well testing, natural gas gathering systems, processing plant operations, crude oil production, pipeline operations, petroleum refining and chemical fertilizer and steel production.

Carbon dioxide emissions from the combustion of landfill gas are not included in flaring emissions, but are included in the CO_2 Emissions from the Combustion of Biomass source category. Methane and N_2O emissions from the combustion of landfill gas must be reported in the Waste and Wastewater source category.

4.1.5 Other Fugitive

Other fugitive emissions are direct emissions that do not fall under Stationary Fuel Combustion Emissions, Industrial Process Emissions, Venting Emissions, Flaring Emissions, On-site Transportation Emissions, Waste and Wastewater Emissions,

Formation CO_2 Emissions, CO_2 Emissions from the Combustion of Biomass or CO_2 Emissions from Decomposition of Biomass and including without limitation intentional or unintentional releases of gases arising from the production, processing, transmission, storage and use of solid, liquid or gaseous fuels.

In general, emissions from other fugitive sources are a result of the handling or processing of various types of fuel in the fossil fuel industry. Other fugitive sources could include leaks from natural gas transmission lines and processing plants, accidental releases from oil and gas wells and releases from the mining and handling of coal.

4.1.6 Formation CO_2

This source category was previously called Vented Raw Gas. It was renamed to better reflect the emissions sources reported in this source category.

Formation CO_2 emissions are direct emissions of carbon dioxide that is recoverable or is recoverable at a well from an underground reservoir and that is gaseous at conditions under which its volume is measured or estimated. This source category includes, but is not limited to, CO_2 emissions vented from gas sweetening and formation gas.

4.1.7 Waste and Wastewater

Waste and wastewater emissions are direct emissions from on-site waste disposal and waste or wastewater treatment and may include without limitation sources of emissions from on-site waste disposal and waste or wastewater treatment at a facility such as landfilling of solid waste, flaring of landfill gas, treatment of liquid waste and waste incineration.

Emissions resulting from waste to energy operations where waste materials are used directly as a fuel or converted to fuel must be included in the Stationary Fuel Combustion source category. CO_2 emissions from the Combustion of Biomass must be reported in the CO_2 Emissions from the Combustion of Biomass source category as described in section 4.1.1 and section 4.1.9 while CO_2 emissions from the decomposition of biomass must be reported in the CO_2 Emissions from the Decomposition of Biomass source category as described in section 4.1.10.

CO_2 emissions from flaring of landfill gas must be reported in the CO_2 Emissions from the Combustion of Biomass source category as landfill gas is considered a biomass emissions. These emissions are included in the emissions threshold calculation, but not included in the calculation of the total annual emissions (TAE) for the facility. CH_4 and N_2O emissions from flaring of landfill gas must be reported in the Waste and Wastewater source category and included in the emissions threshold calculation and the total annual emissions (TAE) for the facility.

4.1.8 On-site Transportation

On-site transportation emissions are direct emissions resulting from fuel combustion in machinery used for the on-site transportation of products and materials integral to the production process. Examples of on-site transportation include the transportation of raw or intermediate products and materials within the production process such as equipment used at an oil sands operation to mine and/or move materials to subsequent on-site processing; equipment used at above or below ground mining operations to mine and/or move mined materials; equipment used to transport intermediate products or materials to different on-site production processes; and transportation of production bi-products such as mining overburden or tailings.

On-site vehicle emissions associated with emergency vehicles, staff transportation, or maintenance are not included in the facility's total direct emissions or total annual emissions calculations.

4.1.9 CO_2 Emissions from Biomass Combustion

Carbon dioxide emissions from the Combustion of Biomass are direct emissions from the combustion of plant materials, animal waste or any product made of either of these and includes without limitation, wood and wood products; charcoal; agricultural residues and wastes including organic material above and below ground, both living and dead such as trees, crops, grasses, tree litter, roots, municipal and industrial wastes where the organic material is biological in origin; landfill gas; bio-alcohols; black liquor; sludge gas; and animal or plant-derived oils.

Carbon dioxide emissions from the Combustion of Biomass including waste incineration must be calculated and included in the calculation of the emissions threshold (total direct emissions), but not included in the calculation of the total annual emissions for the facility. Methane and N_2O emissions from the combustion of biomass must be reported in the Stationary Fuel Combustion source category and included in both the calculation of the emissions threshold and the total annual emissions for the facility.

The carbon dioxide emissions from waste incineration of fossil fuel-based (non-biomass) materials must be reported in the Waste and Wastewater source category and included in both the emissions threshold and total annual emissions calculations for the facility.

Carbon dioxide emissions from flaring of landfill gas must be reported in the CO_2 Emissions from the Combustion of Biomass source category as landfill gas is considered a biomass material. Landfill gas flaring emissions are included in the emissions threshold, but not included in the calculation of the total annual emissions for the facility. However, the CH_4 and N_2O emissions from flaring of landfill gas must be included in the Waste and Wastewater source category, included in the emissions threshold calculation, and included in the total annual emissions for the facility.

4.1.10 CO_2 Emissions from Decomposition of Biomass

This source category was previously called CO_2 Emissions for Anaerobic Decomposition of Waste. The name was changed to better reflect the emissions sources reported in this source category.

Carbon dioxide emissions resulting from the aerobic decomposition of biomass materials in waste must be reported and included in the emissions threshold calculation, but not included in the total annual emissions for the facility. Methane and N_2O emissions from waste decomposition must be reported in the Waste and Wastewater source category and included in the emissions threshold and the total annual emissions calculations for the facility.

4.2 Reporting of Hydrofluorocarbons (HFC), Perfluorocarbons (PFC) and Sulphur hexafluoride (SF_6)

Hydrofluorocarbon (HFCs), perfluorocarbon (PFCs), and sulphur hexafluoride (SF_6) emissions occur in small volumes relative to the principle specified gases—carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O)—but have high global warming potentials. As such, Alberta Environment requires all sources of HFCs, PFCs, and SF_6 associated with facility production operations to be calculated and reported in the facility's threshold calculation and baseline emissions calculations. See section 5.1.1. for instructions on reporting very small emissions sources.

Hydrofluorocarbon, PFC, and SF6 emissions associated with emergency equipment and such sources as office fridges and building air conditioning are not directly related to production and therefore, are excluded from threshold and baseline emissions calculations.

Emissions from industrial process sources are reported but will not be included in the total annual emissions as these emissions are excluded under the *Regulation* and are not reported.

4.2.1 Hydrofluorocarbons (HFC)

Hydrofluorocarbons are a family of synthetic gases that contain carbon, hydrogen and fluorine. Although emissions of hydrofluorocarbons are usually very small, species of HFC often have very large global warming potentials, ranging from 140 to 11700 (see Table 2). HFC emissions from applications such as refrigeration, air conditioning, aerosol propellants, fire extinguishers, some solvents, etc. are not directly associated with production and therefore, are not required to be reported under the *Regulation*.

Sources of HFC emissions from industrial processes are direct emissions from an industrial process involving chemical or physical reactions, other than combustion, and where the primary purpose of the industrial process is not energy production. Industrial Process emissions are included in the facility's total direct emissions calculation for

comparison to the emissions threshold, but are excluded from the facility's total annual emissions calculation.

Sources of HFC emissions from industrial product use are all emissions associated with production that do not meet the industrial process definition. These include without limitation emissions from foam blowing and the use of HFC as a cover gas in metal production. These emissions are included in both the total direct and total annual emissions calculations.

4.2.2 Perfluorocarbons (PFC)

Perfluorocarbons are a family of industrial gases. Although emissions of PFC are usually very small, species of PFC have significant global warming potentials ranging from 6500 to 9200 (see Table 4). Perfluorocarbons emissions from applications such as refrigeration, air conditioning, semiconductor manufacturing, aerosol propellants, fire extinguishers, some solvents, etc. are not directly associated with production and therefore, must not be reported under the *Regulation*.

Sources of PFC emissions from industrial processes are direct emissions from an industrial process involving chemical or physical reactions, other than combustion, and where the primary purpose of the industrial process is not energy production. Industrial Process emissions are included in the facility's total direct emissions calculation for comparison to the emissions threshold, but are excluded from the facility's total annual emissions calculation.

Sources of PFC emissions from industrial product use are all emissions associated with production that do not meet the industrial process definition. These include without limitation emissions from aluminum production and foam blowing. These emissions are included in both the total direct and total annual emissions calculations.

4.2.3 Sulphur Hexafluoride (SF_6)

Sulphur hexafluoride is a synthetic gas that is relatively inert due to its specific chemical properties. Emissions of SF_6 are usually small; however, this gas has a significant global warming potential of 23,900. Emissions must be reported and included in the baseline and compliance report emissions calculations for the facility. Sulphur Hexafluoride emissions from applications such as fire suppression, explosion protection, leak detection and electronic applications are not directly associated with production and therefore, must not be reported under the *Regulation*.

Sources of SF_6 from industrial processes are direct emissions from an industrial process involving chemical or physical reactions, other than combustion, and where the primary purpose of the industrial process is not energy production. Industrial Process emissions are included in the facility's total direct emissions calculation for comparison to the emissions threshold, but are excluded from the facility's total annual emissions calculation.

Sources of SF_6 emissions from industrial product use are all emissions associated with production that do not meet the industrial process definition. These include without limitation emissions from SF_6 being used as a cover gas in magnesium smelting and casting, as foundry products in the aluminum industry, and as an insulating gas in electrical equipment such as circuit breakers and on-site power stations. These emissions are included in both the total direct and total annual emissions calculations.

4.3 Emission Estimation Methodologies

There are several measurement and calculation options available for the different categories of emission sources. Each has an associated level of accuracy with the measured parameter data (e.g., fuel consumption) and the calculation method (e.g., mole balance). Where possible, Alberta Environment recommends the use of data of highest accuracy available (see Table 6 below) and should not fall below either extrapolation from historical data, or generic emissions factors respectively. Emphasis should be placed on the largest sources of greenhouse gas emissions.

Measured Data	Accuracy*	Calculation
Monitoring or direct measurement	Most	Mole balance with efficiency factors
Intermittent (periodic) direct measurement		Equipment-specific emission factors
Calculated based on measured surrogate parameters		Manufacturer's emission factors
Extrapolated from historical data		Models based on surrogate parameters
Estimated from design requirements		Generic emission factors
Estimated from agreements	Least	Top-down emission factors

Table 4: Relative Accuracy of Emission Estimation Methodologies

* Alberta Environment does not support measured data or emissions calculations that fall below the black line for the respective categories unless it can be demonstrated that this level of accuracy will not materially affect the facility's submission.

The following is a description of the six measured data categories in decreasing order of accuracy:

- Monitoring or direct measurement uses Continuous Emissions Monitoring Systems (CEMS). Where greenhouse gases are directly measured, a calculation methodology does not need to be specified.
- Intermittent (periodic) direct measurements use source (stack) testing, which is a "snapshot measurement in time". The measurement result is then extrapolated over a period of time to determine emission values for that period of time.

- Calculated based on surrogate measures uses correlations developed between measured emission rates and related parameters. This is the most common form of measurement (e.g., fuel consumption).
- Extrapolation from historic data uses past information to determine current operating conditions (e.g., runtime and loads).
- Estimates from design requirements uses design information and facility configuration to determine likely values (e.g., power requirements for equipment determine fuel consumption).
- Estimates from agreements use contractual arrangements to provide a product or service to determine likely values (e.g. power supplied, fuel delivered).

The following is a description of the six calculation categories in decreasing order of accuracy:

- Mole balance with efficiency factors determines an emission factor based on the mole balance of carbon between the input and the output of a source, with some assumed efficiency factor.
- Equipment-specific emission factors are determined based on the measurement of the input and output of the equipment at an operating condition similar to normal operations.
- Manufacturer's emission factors are determined based on manufacturer testing.
- Models based on surrogate parameters can derive emission factors based on scientific models that do not have a parameter directly related to the emission (e.g. soil surface temperature and methane emissions from a coal pile).
- Generic emission factors based on a sample of equipment.
- Top-down emission factors based on the aggregate numbers averaged over a large population.

Alberta Environment has reviewed the calculation methods listed in Table 7 and deemed them acceptable for calculating specified gases under the *Specified Gas Emitters Regulation*. These calculation methods may not cover all regulated industries in Alberta. Facilities may propose facility or sector-specific calculation methodologies if it can be demonstrated the alternate calculations will result in higher accuracy and a better reflection of the facility's emissions profile. Alberta Environment encourages the development of sector-specific calculation methodologies and further refinement of the approved calculation methods. However, the use of alternate calculation methodologies must be pre-approved.

Facilities using these alternate calculation methodologies must include an explanation of the methodology in the Baseline Application, including a statement on the uncertainty associated with the calculation method. The calculation methods used **must** be consistent across all baseline years for the facility. This is to ensure that changes in the quantities of greenhouse gas emissions between years are actual changes in the quantities of greenhouse gases released and not the result of changes in methods used to calculate/estimate the facility's emissions.

Facilities must use the same calculation methods for the Baseline Application and Annual Compliance Reports. If a better, more accurate methodology is determined for a facility's annual compliance report, the facility must check with Alberta Environment before using the new methodology. As per section 3.3 of this guidance document, changes in methodology may require the facility to restate its baseline emissions intensity.

Reference	Method	Stationary Fuel Combustion	Industrial Process	Fugitive	Biomass Combustion	Other (incl. Flaring and Venting, Mobile)
1	EC Sector-Specific Guidance	✓	✓			✓
2	CAPP 2005	✓	✓	✓		✓
3	CAPP 2003	✓	✓	✓		
4	CAPP 1999	✓	✓			
5	SGA 2000	✓				
6	CSA 2007	✓		✓	✓	✓
7	ICFPA 2005a	✓	✓		✓	✓
8	ICFPA 2005b	✓	✓		✓	✓
9	US EPA AP 42	✓				
10	API 2004	✓	✓	✓		✓
11	GRI-GLYCalc			✓		
12	GHG Protocol	✓	✓		✓	✓

Table 5: Emission Calculation Methods Acceptable to Alberta Environment

1. Environment Canada, 2003, 2004, *Sector-Specific Guidance Manuals and Protocols (Aluminium Production, Base Metals Smelting/Refining, Cement Production, Primary Iron and Steel Production, Lime Production, Primary Magnesium Production and Casting, Metal Mining)*, www.ec.gc.ca/pdb/ghg/guidance/calcu_pro_e.cfm, accessed June 14, 2007.

2. Canadian Association of Petroleum Producers (CAPP) and Clearstone Engineering, 2005, *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry, Volume 3 Methodology for Greenhouse Gases [2005-0013]* and *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry, Volume 5, Compendium of Terminology, Information Sources, etc. [2005-0015]*, www.capp.ca/default.asp?V_DOC_ID=763&SubjectID=414802, accessed June 14, 2007.

3. Canadian Association of Petroleum Producers (CAPP) and Atlus Environmental Engineering Ltd, 2003, *Calculating Greenhouse Gas Emissions [2003-0003]*, www.capp.ca/default.asp?V_DOC_ID=763&SubjectID=414802, accessed June 14, 2007.

4. Canadian Association of Petroleum Producers (CAPP) and Atlus Engineering Ltd., 1999, *CH_4 and VOC Emissions from the Canadian Upstream Oil and Gas Industry – Volume 3 [1999-0011]*, www.capp.ca/default.asp?V_DOC_ID=763&SubjectID=414802, accessed June 14, 2007.

5. SGA Energy Limited, 2000, *Emission Factors and Uncertainties for CH_4 and N_2O from Fuel Combustion*, www.sgaenergy.com/Experience/PE23.htm, accessed June 14, 2007.

6. Canadian Standards Association, 2007, *Canadian GHG Challenge Registry Guide to Entity & Facility-Based Reporting*, www.ghgregistries.ca/assets/pdf/Challenge_Guide_E.pdf, accessed June 14, 2007.

7. The International Council of Forest and Paper Associations (ICFPA), 2005, *Calculation Tools for Estimating Greenhouse Gas Emissions from Wood Product Facilities*, www.wbcsd.org/web/projects/forestry/Pulp-and-Paper-Tool-Guidance.pdf, accessed June 14, 2007.

8. The International Council of Forest and Paper Associations (ICFPA), 2005, *Calculation Tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills*, www.wbcsd.org/web/projects/forestry/Pulp-and-Paper-Tool-Guidance.pdf, accessed June 14, 2007.

9. United States Environmental Protection Agency (US EPA), 1995 - 2007, *Compilation of Air Pollutant Emission Factors (AP 42) and supplements and updates*, www.epa.gov/ttn/chief/ap42/, accessed June 14, 2007.

10. American Petroleum Institute (API), 2004, *Compendium of Greenhouse Gas Emissions Estimations Methodologies for the Oil and Gas Industry*, www.api.org/ehs/climate/new/upload/2004_COMPENDIUM.pdf, accessed June 14, 2007.

11. Gas Technology Institute (GTI), 2000, *GRI-GLYCalc Glycol Dehydrator Emission Estimation Software*, www.gastechnology.org/webroot/app/xn/xd.aspx?it=enweb&xd=10abstractpage\12352.xml, accessed June 14, 2007.

12. World Business Council for Sustainable Development (WBCSD)/World Resources Institute (WRI), 2001 - 2007, *Calculation Tools*, www.ghgprotocol.org/templates/GHG5/layout.asp?type=p&MenuId=OTAx, accessed June 14, 2007.

5.0 Calculating a facility's Emissions Intensity

The following section provides support for calculating a facility's emissions, production and the emissions intensity. Many of the fields in the baseline emissions intensity application form are calculated automatically based on data input by the facility. However, the calculations below can assist the Reporter to check the calculated information.

5.1 Threshold (Total Direct Emissions) Calculation

The purpose of calculating an emissions threshold is to determine whether a facility is included in the *Specified Gas Emitters Regulation*. All large industrial facilities in Alberta emitting over 100,000 tonnes of carbon dioxide equivalent per year are required to reduce their emissions intensity by 12 per cent below their established baseline emissions intensity. Covered sectors in Alberta include, but are not limited to:

- Cement
- Chemicals
- Forest Products
- Fertilizer
- Gas Plants
- Heavy Oil
- Landfills
- Lime
- Manufacturing
- Oil Sands
- Petroleum Refining
- Power Plants

All greenhouse gas emissions sources associated with a facility's operations must be included in determining the facility's total direct (TDE), and total annual emissions (TAE). The following equation shall be used to determine whether a facility's total direct emissions exceeded the 100,000 tonne of CO_2e threshold:

$$\textit{Total Emissions} = \sum_{i=1}^{n} (E_{CO_2 i} \times GWP_{CO_2}) + \sum_{i=1}^{n} (E_{CH_4 i} \times GWP_{CH_4}) + \sum_{i=1}^{n} (E_{N_2 Oi} \times GWP_{N_2 O}) +$$

$$\sum_{v=1}^{m} (E_{PFC_v} \times GWP_{PFC_v}) + \sum_{v=1}^{m} (E_{HFC_v} \times GWP_{HFC_v}) + (E_{SF_6} \times GWP_{SF_6})$$

Where,

"i"	is a particular source category;
"v"	is a particular PFC or HFC species;
"n"	is the number of source categories;
"m"	is the number of species.

E_{CO2} is the direct emissions of CO_2, in the calendar year, measured in tonnes for each source category; *(Note: CO_2 emissions from the combustion of biomass and CO_2 emissions from aerobic decomposition of biomass are included in determining whether the facility exceeded the 100,000 tonne CO_2e threshold but are not included in the calculation of the Baseline Emissions Intensity (BEI) for the facility).*

GWP_{CO2} is the global warming potential of CO_2: 1;

E_{CH4} is the direct emissions of CH_4 in the calendar year, measured in tonnes for each source category;

GWP_{CH4} is the global warming potential of CH_4: 21;

E_{N2O} is the direct emissions of N_2O in the calendar year, measured in tonnes for each source category;

GWP_{N2O} is the global warming potential of N_2O: 310;

E_{PFC} is the total of industrial process emissions and industrial product use emissions restricted to PFC species, in the calendar year, measured in tonnes;

GWP_{PFC} is the global warming potential of PFC species as set out in Table 2.

E_{HFC} is the total of industrial process emissions and industrial product use emissions restricted to HFC species, in the calendar year, measured in tonnes;

GWP_{HFC} is the global warming potential of HFC species listed in Table 2

E_{SF6} is the total of industrial process emissions and industrial product use emissions restricted to SF_6, in the calendar year, measured in tonnes;

GWP_{SF6} is the global warming potential of SF_6: 23900;

5.1.1 Negligible Emissions

Negligible emissions are those emissions released from a source where the total annual emissions from the source are less than 100 tonnes of CO_2e per year. Facilities with negligible emissions sources should state these sources and provide supporting calculations showing that the source is negligible in their baseline application. If the emissions fall below the negligible emissions threshold and were excluded from the baseline, the emissions may also be excluded in the facility's annual compliance report and baseline application. Facilities should check these emissions sources periodically to confirm that the emissions source remains negligible.

5.2 Calculating Total Annual Emissions

The total annual emissions, excluding industrial process emissions, carbon dioxide emissions from the combustion of biomass, and decomposition of biomass must be calculated using an appropriate, government-approved methodology listed in section 4.3. All emissions must be reported in the correct source categories described in section 4.1. The resulting total annual emissions (TAE) from these calculations will be used to calculate the facility's emissions intensity.

5.3 Calculating Production

A facility's production is the total quantity of saleable output (except where the facility does not produce an output) generated by the facility and must comply with the definition of production in section 1(r) of the *Specified Gas Emitters Regulation*. Product is used as a denominator to calculate the facility's emissions intensity and to track changes in performance relative to its emissions over time. A facility must establish an appropriate production metric that accurately reflects the facility's operations and production mix that is consistent with industry accepted normal production unit for the sector to which the facility belongs. This production metric should reflect the main greenhouse gas activities at the facility and should result in a stable denominator metric if the facility's operations remain unchanged. By having a stable denominator metric, the facility will be able to demonstrate real reductions in greenhouse gases as a change in emissions per unit production.

Total annual production for a facility is calculated as the total saleable product produced by that facility. All major production items associated with the release of greenhouse gas emissions must be included and expressed in units of production appropriate for their operation that are widely accepted by the industry to which the facility belongs. All units of production must be specified in the *International System of Units (SI units)*.

The *Specified Gas Emitters Regulation* describes Production as the quantity, expressed in the applicable units of production, of

(i) end product produced by a facility, or
(ii) any input, output or other thing specified under subsection (4) of the *Regulation*.

Subsection (4) of the *Regulation* states:

> *If a facility* ***does not*** *produce an end product, the director may specify an input, output or other thing as the standard of measurement of production of the facility for the purposes of this Regulation.*

A facility that does not have an end product (e.g.: landfill) may use a different denominator metric.

Alberta Environment has received baseline applications using intensity metrics that did not use end product in the denominator metric. These included Refinery Activity Index (RAI) and Inlet Gas as Production metrics. These alternate denominators are being reviewed to better understand their relevance, ability to track against a facility's emissions, the impacts of changes over time and potential changes to more stringent reduction targets. For the time being, facilities using alternate denominator metrics must submit compliance reports with both the proposed denominator metric and with actual production data until such time as the Director reaches a decision on these metrics. Alberta Environment will make a final determination on these denominator metrics in 2009.

5.4 Calculating the Baseline Emissions Intensity

A facility's baseline emissions intensity is used as a reference point to calculate greenhouse gas emissions reductions at the facility. The baseline intensity should be reflective of the facility's normal operating conditions. If the baseline period does not accurately reflect the facility's operating conditions, the Reporter should review section 3.2 Alternate Baselines and contact the Director to discuss a more appropriate baseline period for their facility.

The baseline emissions intensity for a facility subject to the *Regulation* is calculated by dividing total annual greenhouse gas emissions (TAE) by the total annual production for the facility where the TAE excludes industrial process emissions, CO_2 Emissions from Combustion of Biomass, and CO_2 Emissions from the Decomposition of Biomass.

5.4.1 Established Facility

The baseline emissions intensity (BEI) for an **established facility** is determined by calculating the average of the ratio of total annual emissions (TAE) to Production (P), expressed in the appropriate unit of production, for the years 2003 through 2005, as expressed in the following formula:

$$\mathbf{BEI} = \frac{\left(\frac{\mathbf{TAE}_{2003}}{\mathbf{P}_{2003}} + \frac{\mathbf{TAE}_{2004}}{\mathbf{P}_{2004}} + \frac{\mathbf{TAE}_{2005}}{\mathbf{P}_{2005}} \right)}{3}$$

Where:

BEI is baseline emissions intensity;

TAE is total annual emissions for the year indicated;

P is production for the year indicated

5.4.2 **New Facility**

The baseline emissions intensity for a **new facility** is determined by calculating the ratio of total annual emissions to production for the third year of commercial operation of the facility as expressed in the following formula:

$$BEI = \frac{TAE_3}{P_3}$$

Where:

BEI is baseline emissions intensity;

TAE_3 is total annual emissions for the 3rd year of commercial operation;

P_3 is production for the 3rd year of commercial operation;

6.0 Cogeneration

The following section provides guidance to facilities submitting baseline application forms with integrated or stand-alone cogeneration.

Cogeneration is the combined production of heat for use in manufacturing processes and the production of electricity as a by-product. Electricity not used within the plant may be offered to the competitive electricity market. Combined use of heat in production and to generate electricity improves the overall efficiency of the plant and can displace higher polluting coal-generated power. Treatment of cogeneration under the *Specified Gas Emitters Regulation* recognizes the environmental benefit associated with the higher energy efficiencies generally afforded by cogeneration operations.

The cogeneration calculation methodology assumes that during the baseline period, the heat was sourced from a conventional boiler operating at an efficiency of 80 per cent and the electricity was produced from an NGCC (Natural Gas Combined Cycle) electricity generation plant with a greenhouse gas intensity of 0.418 tonnes/MWh. Corresponding deemed greenhouse gas emissions for the heat and electricity generation are then calculated using the formula provided later in this section.

Stand-alone and integrated cogeneration facilities may choose to calculate deemed greenhouse gas emissions in order to obtain an adjustment to their baseline emissions intensity or they may choose to be treated as a non-cogeneration facility and calculate their baseline emissions intensity using the methods described in section 4.3 of this guide. The Person Responsible must select the appropriate baseline application form applicable to their facility's normal operating conditions. Facilities with cogeneration not wishing to claim a deemed efficiency for cogeneration must complete the established or new facility baseline application forms. Facilities wishing to claim deemed efficiency for cogeneration must submit either the integrated or stand-alone cogeneration baseline application form.

All facilities submitting as integrated or stand-alone cogeneration must also submit an adjustment factor (A_T) calculated as a difference between deemed greenhouse gas emissions and actual greenhouse gas emissions for the baseline period. This adjustment factor is used to estimate the impact of the cogeneration calculation methodology on the environment and is collected for information purposes only.

6.1 Definitions

Standalone cogeneration facilities are those units that derive all their energy outputs from on-site fuel combustion. These units do not have any other external energy inputs. All the thermal and electrical output should be traced down to single source.

Integrated cogeneration facilities are those units that, in addition to their own fuel source, also have other sources contributing to generating thermal or electrical output. This source could be combustion at the host site, any exothermic reaction or in some cases import or export of steam from a second heat source depending upon demand.

6.2 Cogeneration Reporting Requirements

Reporting requirements for cogeneration facilities differ from reporting requirements for regular facilities. This is to recognize the environmental benefits of combined production of heat and power at a facility. Facilities choosing to calculate deemed greenhouse gas emissions associated with their cogeneration must provide the following information in the Baseline Emissions Intensity Application Form:

- Total greenhouse gas emissions (G_T) in tonnes CO_2e from the cogeneration facility in the baseline year(s);
- Actual fuel used by the cogeneration facility in the baseline year(s);
- If fuel factors are used to calculate the greenhouse gas emissions, provide the factors with references;
- If fuel analysis is used to calculate the greenhouse gas emissions, provide a synopsis of the fuel analysis;
- Total net heat production (H) in GJ by the cogeneration facility in the baseline year(s);
- Mass/volume of fuel deemed used to produce heat in the baseline year(s);
- Deemed greenhouse gas emissions from heat production (D_H) in tonnes CO_2e in the baseline year(s);
- Total gross electricity production (E) in MWh by the cogeneration facility in the baseline year(s);
- Deemed greenhouse gas emissions from electricity generation (D_E) in tonnes CO_2e in the baseline year(s); and
- Total Cogeneration Baseline Adjustment (A_T) in tonnes CO_2e in the baseline year(s);

The Person Responsible should also provide the following information in either the comments section of the Baseline Application or in a separate document:

- A simple conceptual/logic diagram of the cogeneration layout, boundary and control volume;
- A description of the cogeneration boundary and control volume used for calculations;
- An explanation of how heat calculations were done, including how the enthalpies were averaged;
- List the thermal streams and annualized flow averages, temperature averages and pressure averages for each stream;
- Hours of operation of the cogeneration facility in the baseline year(s).

6.3 Total Annual Greenhouse Gas Emissions

Total Annual greenhouse gas emissions for both integrated and stand-alone cogeneration facilities are calculated according to the following formula:

$$G_T = f \times M_F$$

Where:

G_T	=	Total annual greenhouse gas emissions from the cogeneration facility	[tonnes CO_2e]
f	=	Emission factor for the fuel used in the cogeneration facility	[tCO_2e/fuel used]
M_F	=	Mass/volume of fuel used in the cogeneration facility	[tCO_2e/fuel used]

The Person Responsible may choose to:

1) Calculate site-specific emission factors for the fuel used in the facility based on compositional analysis of the fuel. If this method is used, the Person Responsible should report the detailed fuel analysis and calculation procedures used to develop the emission factor in section D2 of the baseline application.
2) Use an industry standard emission factor. If this method is used, the Person Responsible should provide references for the source of the emission factor.

Note: Carbon dioxide (CO_2) emissions from biomass are not included in the G_T calculations. Treatment of CO_2 emissions from biomass is discussed in section 4.1.

6.4 Deemed Greenhouse Gas Emissions for Heat Generation

Deemed greenhouse gas emissions are calculated according to the methodology outlined below.

6.4.1 Standard Calculation Methodology for Determining Heat Production from the Facility

Mass energy balance principle is an acceptable calculation methodology for calculating net heat production from a cogeneration facility. Mass energy balance can capture all the components of the heat and steam exchange and quantify the heat transfer at large facilities where the host facility and cogeneration unit are interconnected through various thermal streams that help with the exchange of different types of steam.

The net heat produced by the cogeneration facility is calculated based on the difference between:

- The total energy content of the thermal streams leaving the cogeneration facility; and
- The total energy content of the thermal streams entering the cogeneration facility.

These values would be aggregated over the reporting period.

It means[1]:

$$H_t = \sum_{i=1}^{n} \{h(steam)_i \times M(steam)_i\} - \sum_{i=1}^{m} \{h(condensate)_i \times M(condensate)_i\}$$

Where:

H_t	=	Heat produced by the cogeneration facility per hour	[kJ/h]
$h(steam)_i$	=	Enthalpy of i streams of steam to the steam host	[kJ/kg]
$h(condensate)_i$	=	Enthalpy of i streams of condensate returned to the cogeneration unit	[kJ/kg]
$M(steam)_i$	=	Mass flow rate of i streams of steam	[kg/h]
$M(condensate)_i$	=	Mass flow rate of i streams of condensate	[kg/h]
n	=	Total number steam streams	
M	=	Total number of condensate streams	

Therefore, total heat produced by the cogeneration facility during the baseline year(s), H, will be:

$$H = H_t \times \text{Hours of Operation}$$

Where the cogeneration facility has a more complex heat transfer profile, these sites should calculate their net heat production based on their actual heat balance. More information on calculating emissions from cogeneration facilities is available in the *Additional Guidance for Cogeneration* document.

6.4.2 Calculate the Deemed Greenhouse Gas Emissions for Heat Production

Deemed emissions from heat production are determined from the input energy attributed to heat production based on a boiler thermal efficiency of 80%. This input energy is the energy derived from fuel combustion that is attributable to useable heat production.

$$E_H = \frac{H}{0.8}$$

Where:

E_H	=	Deemed input energy attributed to heat production	[GJ]
H	=	Total heat produced by the cogeneration facility during the baseline year(s)	[GJ]

[1] *Alberta Air Emission Standards for Electricity Generation*. Alberta Environment, Government of Alberta. December 2005.

Next, calculate the fuel required to generate the deemed input energy.

$$M_H = \frac{E_H}{V}$$

Where:

M_H	=	Mass/volume of fuel deemed to be used to produce heat	[units of fuel used]
V	=	Fuel Heating Value	[GJ/units of fuel used]

Different sectors have different conventions regarding the use of Higher Heating Value (HHV) and Lower Heating Value (LHV) in energy calculations. The Reporter should use the heating value most appropriate to the sector in which that cogeneration facility belongs. This heating value must be applied consistently across baseline and compliance years.

The deemed greenhouse gas emissions allocated to heat production are calculated according to:

$$D_H = f \times M_H$$

Where:

D_H	=	Deemed greenhouse gas emissions from heat production	[tonnes CO_2e]
f	=	Emission factor for the fuel used in the stand-alone boiler facility.	[tonnes CO_2e/units of fuel used]

6.5 *Deemed Baseline Greenhouse Gas Emissions for Electricity Generation*

Deemed greenhouse gas emissions are calculated according to the methodology outlined below and are associated with electricity production.

6.5.1 Measure the Total Electricity Generated by the Cogeneration Facility

Deemed emissions associated with electricity generation are calculated based on total (gross) electricity produced at the facility. Gross electricity is used to cover all electricity from cogeneration including electricity used by the heat host. This methodology measures all electricity at the facility and does not differentiate between electricity used within the heat host's process and electricity exported to Alberta's electricity grid.

6.5.2 Calculate the Deemed Greenhouse Gas Emissions for Electricity Generation

Deemed emissions associated with electricity are base on an NGCC turbine operating at an emissions intensity of 0.418 tonnes CO_2e/MWh. These emissions are calculated according to the following formula:

$$\mathbf{D_E = 0.418 \times E}$$

Where:

D_E	=	Deemed greenhouse gas emissions from electricity generation	[tonnes CO_2e]
E	=	Total electricity generation by the cogeneration facility during the baseline year(s).	[MWh]

6.6 Cogeneration Adjustments

The baseline emissions intensity of a cogeneration unit is adjusted using the deemed emissions calculations above. The deemed emissions adjustment essentially adjusts the facility's baseline to reflect an equivalent facility operating without a cogeneration unit. The baseline adjustment factor calculated below is used to determine the actual greenhouse gas emissions at the facility. This adjustment factor must be calculated and reported to Alberta Environment to ensure that the province's greenhouse gas emissions inventory tracks total greenhouse gas emissions for the province. This will prevent double counting within the provincial and national inventories. This adjustment is for information purposes only and is not applied to the actual baseline emissions intensity calculation for the cogeneration facility.

The Total Cogeneration Baseline Adjustment is calculated according the following formula:

$$\mathbf{A_T = [D_H + D_E] - G_T}$$

Where:

A_T	=	Total Cogeneration Baseline Adjustment	[tonnes CO_2e]
D_H	=	Deemed greenhouse gas emissions attributed to heat production	[tonnes CO_2e]
D_E	=	Deemed greenhouse gas emissions attributed to electricity generation	[tonnes CO_2e]
G_T	=	Total annual greenhouse gas emissions from the cogeneration facility	[tonnes CO_2e]

6.7 Baseline Intensities

The baseline emissions intensity calculations differ between integrated and stand-alone cogeneration facilities. Integrated cogeneration units may have multiple products depending on the nature of the facility. Electricity generation is not included as a product at these facilities. Stand-alone cogeneration facilities produce heat and electricity; however, emissions associated with electricity generation are not included in the baseline emissions intensity calculation.

6.7.1 Integrated Cogeneration Facility

For facilities with integrated cogeneration units, the additional emissions related to generating electricity are excluded from the emissions intensity calculation. The emissions intensity calculation for integrated facilities is expressed in the following formula:

$$I = \frac{(TAE - G_T) + D_H}{P}$$

$$BEI = \frac{I_{2003} + I_{2004} + I_{2005}}{3}$$

Where:

I	=	Greenhouse gas emissions intensity for each baseline year.	[tonnes CO_2e /units of P]
BEI	=	Baseline emissions intensity.	[tonnes CO_2e /units of P]
TAE	=	Total annual greenhouse gas emissions from entire the facility for each baseline year. ***(excluding:*** *GHG emissions from industrial process, CO_2 emissions from combustion of biomass and CO_2 emissions from aerobic decomposition of biomass).*	[tonnes CO_2e]
G_T	=	Total annual greenhouse gas emissions from cogeneration for each baseline year.	[tonnes CO_2e]
D_H	=	Deemed greenhouse gas emissions from heat production for each baseline year.	[tonnes CO_2e]
P	=	Production for each baseline year.	[appropriate units of production]

6.7.2 Stand-Alone Cogeneration Facility

Stand-alone cogeneration facilities must calculate their baseline emissions intensity using the following formula:

$$BEI = \left[\frac{D_H}{H} \right]$$

Therefore, the baseline intensity for the 2003-2005 period will be:

$$BEI = \left[\frac{D_{H,2003}}{H_{2003}} + \frac{D_{H,2004}}{H_{2004}} + \frac{D_{H,2005}}{H_{2005}} \right] /3$$

Where:

BEI	=	Baseline Emissions intensity.	[tonnes CO_2e / GJ]
D_H	=	Deemed greenhouse gas emissions attributed to heat production	[tonnes CO_2e]
H	=	Total net heat produced by the cogeneration facility during the baseline year(s).	[GJ]

6.8 Marginal Environmental Improvement

The cogeneration adjustment factor is intended to recognize environmental improvements gained at the facility. If the Director determines there is only marginal environmental improvement resulting form the cogeneration, all or part of the Cogeneration Adjustment may be removed from the baseline emission intensity. This would result if the facility was using older cogeneration technology or a high carbon fuel where the 0.418 tonnes CO_2e/MWh is not relevant. These facilities will be reviewed on a case-by-case basis.

6.9 Significant Change in Cogeneration Unit Operation

If the operation of the cogeneration facility changes such that there is no material production of one of the energy products, all or part of the Cogeneration Adjustment may be removed from the baseline emissions intensity. This situation could arise if the host facility decreased its take of energy from the cogeneration plant such that one or more of the products was no longer used. These situations will be reviewed on a case-by-case basis.

6.10 Alberta Environment Cogeneration Policy Review

Alberta Environment has identified the cogeneration policy as an area for review following the 2007 compliance period. As such, it has convened a working group of industry, environment organizations, and government to review the current cogeneration policy and determine what, if any, changes will need to be made to balance recognition of the environmental benefits of cogeneration with continuous improvement and greenhouse

gas emissions reductions over time. Results from this working group will be applied to the 2009 compliance period.

7.0 Data Confidentiality and Access to Information

7.1 Request for Confidentiality

In accordance with Section 16 of the *Regulation*, the Certifying Official may request certain information in the Baseline Application be kept confidential for a period of up to five years on the basis that the information is commercial, financial, scientific or technical information that would reveal proprietary business, competitive or trade secret information about a specific facility, technology or corporate initiative. Confidentiality can be granted to specific portions of the baseline application, but cannot be granted for the entire application form. The Certifying Official must state the specific information he/she wishes to have kept confidential and include justification for the request by the June 1 baseline application deadline. If additional information is requested, the facility may submit a written request for confidentiality and supporting justification along with the information.

Each confidentiality request will be reviewed by Alberta Environment and a decision rendered by the Director within 150 days from the letter of submission date. During this time, the portions of the information for which confidentiality has been requested will be considered prescribed information under the Freedom of Information and Protection of Privacy Act.

Note: requests for confidentiality submitted after the compliance deadline may not be accepted by Alberta Environment.

The confidentiality request and evaluation is described in Figure 2 below.

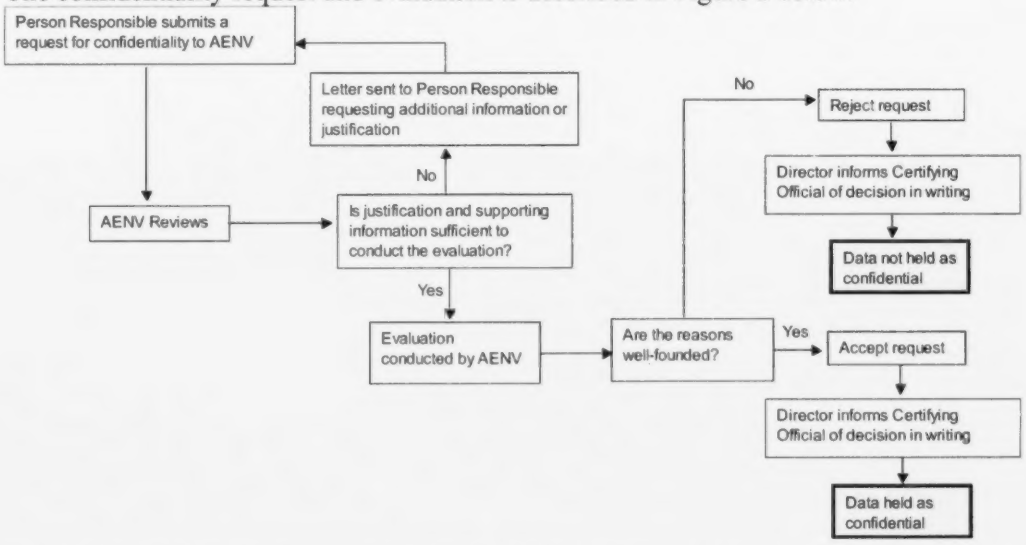
Person Responsible submits a request for confidentiality to AENV
Letter sent to Person Responsible requesting additional information or justification
No
AENV Reviews
Is justification and supporting information sufficient to conduct the evaluation?
Yes
Evaluation conducted by AENV
Are the reasons well-founded?
No
Reject request
Director informs Certifying Official of decision in writing
Data not held as confidential
Yes
Accept request
Director informs Certifying Official of decision in writing
Data held as confidential

Figure 2: Confidentiality Process for the Specified Gas Emitters Program.

As per section 17 of the *Regulation*, the Director must submit an annual confidentiality report to the Information and Privacy Commissioner. This report must include the number of confidentiality requests received, number of confidentiality requests approved, and the period of time prescribed for each approved request.

7.2 Access to Baseline Application Information

Prescribed (confidential) information may be published in aggregate form such that individual facility information cannot be identified.

Non-confidential information contained in the baseline application or compliance report may be published in any form or manner the Director considers appropriate.

Persons wishing to access baseline or compliance information that has not been deemed confidential may submit written requests for information directly to the facility, or to the Director, Alberta Environment. Figure 3 shows the process for requesting access to information reported under the *Regulation*.

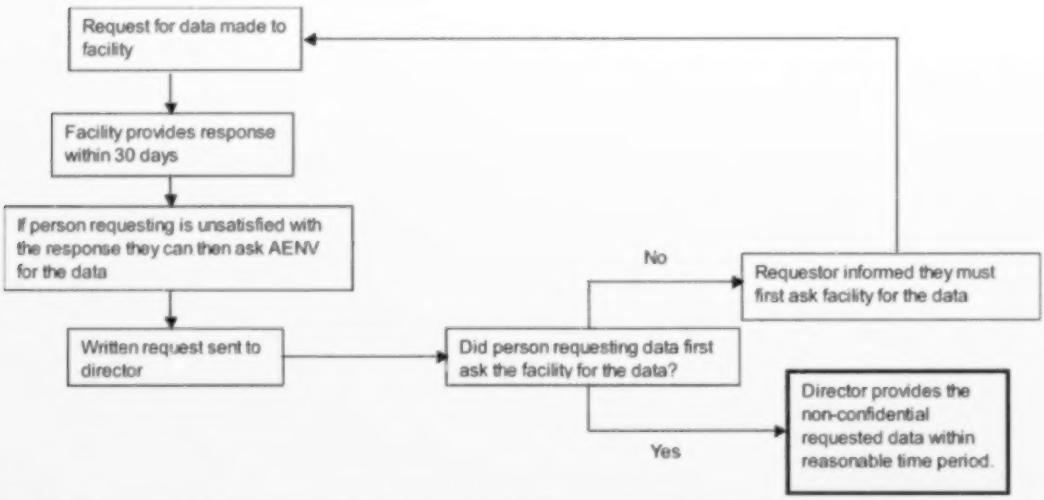
Request for data made to facility
Facility provides response within 30 days
If person requesting is unsatisfied with the response they can then ask AENV for the data
Written request sent to director
Did person requesting data first ask the facility for the data?
No
Requestor informed they must first ask facility for the data
Yes
Director provides the non-confidential requested data within reasonable time period.

Figure 3: Process for Requesting Non-Confidential Information Reported Under the Specified Gas Emitters Regulation.

8.0 Verification by Third Party Verifier

Third Party Verification is intended to provide an independent third party review of the facility's baseline application before it is submitted to Alberta Environment. This review provides additional assurance that the baseline applications received are reliable and of sufficient quality to determine the facility's baseline emissions intensity.

The requirement for third party verification is consistent with international standards requiring independent, third party verification for greenhouse gas inventories. The Third Party Verifier's Report is used for information purposes to assist Alberta Environment in reviewing and understanding the facility's submission. Third Party review should flag discrepancies in reported data, identify areas where the interpretation in the reported data differs from the guidance provided by Alberta Environment, and flag material and immaterial discrepancies encountered. Facilities are encouraged to review the verification report, and where possible, make corrections to their submission prior to submitting their baseline application. This ensures greater accuracy and correctness in the final submission. However, the audience for the Third Party Verifier's Report is Alberta Environment. As such, this report must meet the requirements outlined in section 8.3.4 below. Third Party Verifier's Reports that do not meet these requirements may be deemed incomplete. Incomplete reports will not be accepted by Alberta Environment and could result in the facility's baseline application being considered incomplete and the facility being deemed out of compliance with the *Specified Gas Emitters Regulation*.

Alberta Environment will conduct an annual audit on up to 10 per cent of the baseline applications received. Alberta Environment's audit process is described in more detail in section 9.0.

The following section provides guidance to facilities undergoing third party verification.

8.1 Peer Review Process

Alberta Environment has adopted ISO 14064: Part 3 as the verification standard for greenhouse gas emissions reporting in the province. ISO14064: Part 3 clause 4.8 notes that, ISO14065 and some GHG programs require a "peer review" be conducted. This peer review process requires that persons different from those who undertook the fieldwork (i.e. assessed the GHG Information System and its controls, the GHG data and information, and conducted the assessment against the verification criteria) perform a final evaluation of the evidence and conclusions of the verification team.

Third party verification performed by a Third Party Verifier provides an independent, third party review of a facility's data management and specified gas compliance reporting. This process provides Alberta Environment additional assurance that there are no significant anomalies and that the information reported is accurate and consistent with the requirements of the *Specified Gas Emitters Regulation*.

Alberta Environment has not pre-approved third party verifiers. Minimum qualifications for third party verifiers are specified in the *Regulation* and in this document. Third Party Verifier credentials and supporting information should be identified in section G of the baseline applications.

8.2 Verification Fundamentals

8.2.1 Terminology

Assurance is used to encompass and define a range of levels of assurance where an assurance practitioner (verifier) is engaged to issue a written communication expressing a conclusion concerning a subject matter for which the accountable party is responsible.

Compilation refers to collecting and completing the facility's baseline application submission. A facility may choose to hire an external, qualified person to complete (compile) the baseline application. This compiled application must be verified by an independent third party verifier prior to being submitted to Alberta Environment.

Limited assurance is a moderate level of assurance, or negative assurance. Limited assurance is based on identifying anomalies rather than confirming an assertion.

Materiality refers to an error, omission or misrepresentation that would affect the GHG assertion stated in the baseline emissions intensity application. Materiality is discussed in section 8.2.7.

Reasonable assurance is a high level of assurance, or positive assurance. Reasonable assurance is a direct factual statement expressing the opinion of the verifier.

Third Party Verifier describes the person or persons conducting the independent, third party review of the facility's submission. The expectation is that the Third Party Verifier will perform a verification of a facility's baseline application submission.

Verification describes the process by which an objective third party examines or reviews an assertion such as a submission to a regulator and provides an opinion or conclusion on the assertion.

8.2.2 Qualifications of the Third Party Verifier

The Third Party Verifier is defined as a qualified person or persons that make up a verification team that verifies and provides assurance on a facility's baseline application.

The lead verifier must be a chartered accountant or professional engineer in good standing and be trained in one of the three acceptable verification methodologies discussed in section 8.2.4. The verification team should have technical expertise in the following areas:

- Data audit practices and data verification standards
- Detailed knowledge of the *Specified Gas Emitters Regulation* and associated requirements
- Verification criteria and their appropriate application within the defined scope of the verification
- Technical expertise for the sector the audit team plans to operate in including:
  - The specific GHG activity and technology
  - Identification and selection of GHG sources, sinks, reservoirs
  - Quantification, monitoring and reporting, including relevant technical and sector issues
  - Situations that may affect the materiality of the GHG assertion, including typical and atypical operating conditions
  - Be able to operate as a business including, policies, finances, and quality review of products or services

The lead verifier must sign and submit the original Statement of Qualification (SoQ).

The Statement of Verification must be signed by a qualified individual on the team with the delegated powers to accept legal responsibility for the information provided.

Electronic signatures are not permissible under the Specified Gas Emitters program.

Note: the *Regulation* requires the Third Party Verifier to be an individual. If a company wishes to sign on behalf of the Corporation, sign-off may be done as:

Company Name
Per [Corporate Binding Official]

All documents must be submitted to Alberta Environment with original signatures from a designated authority or the submission may be deemed incomplete.

8.2.3 Independence

Independence is a surrogate measure for the objectivity of the verifier and is a key qualification of a Third Party Verifier. The Third Party Verifier must be able to demonstrate independence and have the appropriate systems in place to document this independence to be qualified to undertake a third party verification.

The Third Party Verifier must submit a signed original Conflict of Interest (CoI) Checklist with the baseline application.

8.2.4 Verification Standards

Third Party Verifiers must use one of the following verification standards:

- ISO 14064 Part 3 – Greenhouse Gases: Specification with guidance for the validation and verification of greenhouse gas assertions
- Standards for Assurance Engagements, Canadian Institute of Chartered Accountants (CICA) Handbook – Assurance Section 5025
- International Standard on Assurance Engagements (ISAE) 3000 - Assurance Engagements Other Than Audits or Reviews of Historical Financial Information

These standards ensure a consistent level of rigour in the verification process such that a peer verifier or auditor would come to the same conclusion as the original verifier.

8.2.5 Verification Criteria

The following documents provide guidance to assist the verifier in completing the third party verification:

- Climate Change and Emissions Management Act
- Specified Gas Emitters Regulation
- Technical Guidance Document for Completing the 2008 Specified Gas Compliance Reports
- Technical Guidance Document for Completing Baseline Emissions Intensity Applications
- Additional Guidance on Cogeneration Facilities
- Alberta Environment's guidance documents for Offsets projects (see Related AENV publications for a complete list).
- Technical Guidance for Quantifying Specified Gas Emissions from Landfills

8.2.6 Level of Assurance

Alberta Environment requires all baseline applications be verified to a limited level of assurance. This requires the verifier to obtain and check information through enquiry, analytical procedures, and discussion. Greenhouse gas verification done to a limited level assurance is more stringent than financial verification done to a negative level of assurance, but is not sufficient for the Verifier to come to a conclusion. Therefore, a limited level assurance statement should be phrased "Based on our work described in this report, nothing has come to our attention that causes us to believe that the GHG statement is not, in all material respects, in accordance with the approved quantification protocols".

Greenhouse gas emission inventories, data systems, and monitoring is a new and evolving field. Alberta Environment recognizes that the level of sophistication in greenhouse gas emissions monitoring and data systems varies between sectors and facilities. Alberta Environment expects the level of emissions tracking to improve over time, and may require a higher level of assurance in future compliance cycles.

8.2.7 Materiality

Materiality refers to an error, omission or misrepresentation that may affect the GHG assertion stated in the baseline emissions intensity application.

Qualitative materiality refers to errors, omissions or misrepresentations of a non-numerical nature; for example, a misleading presentation of circumstances. Determining whether a qualitative materiality discrepancy has occurred is at the professional judgement of the Third Party Verifier.

Quantitative materiality refers to errors, omissions or misrepresentations of a numerical nature. Examples include inaccuracies in the input data, omission of sources, and inappropriate application of calculation methodology. Third Party Auditors should further breakdown quantitative materiality issues into material and immaterial errors based on a five per cent materiality threshold. That is, errors causing less than five per cent change in over all emissions are deemed **immaterial**. Errors causing a greater than five per cent change in overall emissions are deemed **material**. If the aggregate sum of immaterial errors results in a discrepancy greater than five per cent, the submissions will be deemed to have exceeded the five per cent materiality threshold. Facilities are required to correct material discrepancies before submitting their baseline application.

The Third Party Verifier may issue a limited level verification statement for a submission containing immaterial errors. However, the Third Party Auditor cannot provide a verification statement and report for a baseline emissions intensity application that contains material errors.

8.3 Verification Process

The following sections provide guidance on the verification process.

8.3.1 Engaging a Third Verifier

The Certifying Official is responsible for completing the baseline application and engaging a Third Party Verifier to conduct the verification of the baseline application. The Person Responsible should ensure that the Third Party Verifier hired to complete the verification meets the requirements for a Third Party Verifier identified in section 8.2.2 above.

Both the Certifying Official and Third Party Verifier need to confirm that there are no actual or perceived conflicts of interest that may compromise the impartiality of the Third Party Verifier. The Conflict-of-Interest Checklist (COI) should be filled out as part of the procurement process and be submitted to Alberta Environment as part of the facility's baseline application submission. If the Third Party Auditor is utilising external resource persons on its verification team, the external team members must also complete and submit a Conflict-of-Interest Checklist.

If it is determined that there is a real or potential conflict of interest, and both parties wish to pursue the engagement, written evidence must be provided to Alberta Environment stating that actions will be taken to manage the conflict to preserve actual and perceived independence. Alberta Environment will assess all potential conflict of interest cases.

If a potential conflict of interest cannot be effectively managed, the facility must select an alternate Third Party Verifier that meets the criteria for independence discussed in section 8.2.3.

Impartiality must be monitored through the verification. If an actual or perceived conflict of interest is identified, the Certifying Official must notify Alberta Environment and work with the Third Party Verifier to manage the conflict.

8.3.2 Planning the Verification

The Third Party Verifier should design a verification plan to support a limited level assurance statement for the facility's baseline emissions intensity application. The verification plan should:

1. Set the objectives of the verification.
2. Assess the potential risks in the GHG data management system by
    a. Assessing the inherent and control risk associated with GHG data and data management system to determine areas for further investigation.
    b. Performing analytical testing on the draft GHG assertion to determine areas for further investigation.
3. Assess the potential magnitude of any errors, omissions and misreporting by conducting a magnitude and sensitivity analysis on the reported data to determine parameters that significantly effect the GHG assertion.
4. Set an initial quantitative materiality level for any errors, omissions or misreporting.
5. Design and document a verification plan and sampling plan that details which verification procedures will be applied to meet the objectives of the verification.
6. The verification plan should also show the connections between the verification objectives, risks, magnitude of errors, anomalies, materiality, and procedures and should take into account the GHG data management systems as this determines the control risk for the next verification process.
   For example, one objective should be to determine whether the GHG inventory is complete. The verification procedures for this objective could include:
    - A site visit to inspect and visual confirm the GHG inventory.
    - Inquiring how the client ensured the completeness of the GHG inventory.

The Third Party Verifier and Certifying Official should determine a reasonable timeframe and schedule for the verification up front. This will include identifying key contacts for the facility, setting dates for site visits, and estimating a completion date for the verification. This allows both parties to set up an appropriate verification schedule to complete the verification as efficiently as possible.

8.3.3 Site Visits

Albert Environment encourages third party verifiers to conduct a site visit as part of their verification. Site visits should be used to help confirm the facility's submission including

identification of emissions sources, products and measurement/estimation methods. The site visit is also used to confirm the facility boundary.

If a verifier chooses not to conduct a site visit as part of the verification process justification must be provided in the verification report.

8.3.4 Access to Information and Supporting Materials

The Certifying Official must provide sufficient information to allow the Third Party Verifier to evaluate completeness of the baseline application and render a limited level assurance statement. This includes:

- The Baseline Emissions Intensity Application;
- A description of the site processes;
- A simplified process flow diagram;
- An inventory of GHG sources;
- A brief description of the GHG data management system and quantification protocol used to calculate the GHG emissions;
- Key supporting documents used to compile the baseline application; and
- Where required, access to the facility to conduct a site visit.

Other documents may be requested to support the verification and will be facility specific.

The Certifying Official can assist the verification process by having documents and records collated and available for the Third Party Verifier prior to the commencement of the verification. This will make the verification process easier and less expensive. Appendix B contains a checklist to assist the Person Responsible to prepare documents for verification.

8.3.5 Verification Plan and Sampling Plan

The Third Party Verifier must develop a verification plan and a sampling plan that should be submitted to the facility for review before they begin the detailed verification. Both documents must be included in the Third Party Verifier's Report submitted to Alberta Environment.

The **verification plan** documents the terms of the engagement and the potential verification procedures. Specific verification procedures will be determined based on anomalies encountered in the preliminary testing and risk identification.

The **sample plan** is a supporting document that is developed on-site once the verifiers have done an initial assessment of the robustness of the facility's greenhouse gas emissions data and emission management systems. The sampling plan will typically identify the size of sample required for the verifier to achieve a reasonable level of comfort with the reported data, and render a limited level assurance statement.

8.3.6 Third Party Verification

The Certifying Official can support and facilitate the verification by ensuring that the appropriate staff are available to answer questions and provide information throughout the process. It is important however, that key personnel are made available during the site visit as this greatly improves the verifier's ability to check data in a timely and efficient manner.

8.3.6.1 Closing meeting

The Third Party Verifier is encouraged to provide the draft report to the Certifying Official. Parties may schedule a close-out meeting to review the verification findings and attempt to resolve outstanding issues prior to submitting the baseline application.

The Certifying Official must submit the Third Party Auditor's Report to Alberta Environment with the facility's baseline application.

8.3.7 Verification Report

The Third Party Verifier's Report is a summary and discussion of the Third Party Verifier's verification procedures and results. This report is submitted to Alberta Environment as part of the facility's baseline application package. It should be sufficiently complete to provide Alberta Environment assurance that the values reported in the application are accurate and correct based on the information available.

The Third Party Verifier's report must contain:

- the final verification plan;
- the final sampling plan;
- a complete verification schedule;
- names and roles of verification team members;
- a risk assessment;
- findings identifying any material and immaterial discrepancies found; and
- a limited level assurance statement for the baseline application.

Table 6 contains a template for the Third Verifier's Report that meets the requirements identified above.

Section	Content
1. Verification Report	Summary table containing: Facility identification information Facility contact information Verification objective Verification summary Audit team members Report and audit dates
2. Introduction	Provide an introduction to the facility and the verification. This should include the facility's baseline emissions intensity.
3. Objective	Discuss the objective of the verification
4. Scope	Discuss the scope of the objective
5. Verification Criteria	List the verification criteria used and any relevant, supporting documentation used
6. Final Verification Plan	Provide a detailed discussion of the final verification plan including: • Methodologies • Key emissions sources • Final sampling plan • Other relevant information
7. Audit Schedule	Provide a list of verification activities and dates
8. Verification Procedures	Identify steps taken during the verification including: • Methodologies used to assess/verify emissions data • Details of site visit • Other relevant information
9. Verification Findings	Discuss findings and results: • Material and immaterial discrepancies identified • Data management system and controls • Emissions sources • Process flow diagram for the facility • Facility boundary compared with the facility definition under the *Regulation* • Statement of findings
10. Statement of Verification	This must be the Statement of Verification (SoV) from the compliance report form
11. Verification Team	Clearly identify all team members and their respective duties
12. Appendix	Any relevant documentation such as methodologies, and calculations that provide clarity and assist Alberta Environment in assessing the completeness of the review.

Table 6: Third Party Verifier's Report Template.

Working papers do not need to be included in the Verification Report, but should be retained by the verifier for at least five years, and may be requested by Alberta Environment if additional information or clarification is needed.

8.3.8 Statement of Verification

There are three possible verification statements that can be issued for a limited level of verification:

- a limited level assurance statement
- a qualified limited level assurance statement
- an adverse assurance statement

Limited Level of Assurance Statement
This statement of verification is issued by the Third Party Verifier if the verifier is satisfied that they have undertaken sufficient procedures and there has been sufficient and appropriate evidence supplied to determine that nothing has come to their attention that causes them to believe that the baseline emissions intensity is not fairly stated. This report may be issued despite remaining immaterial discrepancies.

Qualified Limited Level of Assurance Statement
A qualified statement of verification is issued if the verifier is unable to form an opinion on certain aspects of the baseline application due to circumstances beyond the control of the Third Party Verifier or the Certifying Official. Examples include the disposal of records in compliance with regulations or the destruction of records in a natural disaster. Limitations on the scope of the assurance should be clear in the statement of verification and the reasons for the limitation should be disclosed in the Third Party Verifier's report. Further guidance is provided in ISO 14064: Part 3, Annex A.2.9.2.

Adverse Assurance Statement
Adverse assurance statements are rarely issued, but when they are, it is because there are outstanding, unresolved, and undisclosed material discrepancies. Adverse assurance statements may be issued for example, if verification was terminated at the request of the Certifying Official and no Verifier's Report or Statement of Verification was issued. The Certifying Official may consider terminating the verification and ask the Third Party Verifier not to produce the report if they are faced with an adverse verification statement or if they need more time to prepare for the verification. The Certifying Official must inform Alberta Environment if verification is terminated.

8.3.8.1 Content of the Statement of Verification

The Statement of Verification (form SoV in the baseline application) must be completed, printed, signed and submitted to Alberta Environment as the assurance statement for the third party verification. The Statement of Verification must include the following elements:

- identify to whom the report is directed;

- describe the objective, subject matter and time period covered by the verification;
- identify the GHG assertion including the emissions intensity being verified;
- describe the responsibilities of management and the verifier;
- identify the applicable standards used to conduct the verification;
- identify the criteria against which the GHG assertion and supporting evidence was evaluated;
- state a conclusion that conveys the level of assurance being provided and/or any reservation the verifier may have;
- state the date of the report;
- identify the name of the verifier(s) or firm that undertook the verification; and
- identify the place of issue.

An example of a Limited Level assurance statement is:

> Based on our work, nothing has come to our attention that causes us to believe that the Baseline Emission Intensity of Z tonnes of CO_{2e} per year stated in the Baseline Emissions Intensity Application is not presented fairly in accordance with the relevant criteria.

An example of a qualified opinion is:

> Based on our work, there was not sufficient and appropriate evidence to support a conclusion on the Baseline Emissions Intensity during the period xx,xx to xx,xx. As referenced in the Baseline Emissions Intensity Application, records for this period were unavailable. Readers are cautioned that statements during this period may not be appropriate for their purposes. Based on our work during the period zz,zz to zz,zz, nothing has come to our attention that causes us to believe that the Net Emission Intensity presented in the Report for this period is not presented fairly in accordance with the relevant criteria.

An example of an adverse opinion is:

> Based on our work, the Baseline Emissions Intensity Application does not contain all the disclosures required by Alberta Environment. Readers are cautioned that these statements may not be appropriate for their purposes.

8.4 Issues Arising During the Verification

The Third Party Verifier may encounter problems such as errors in the data entry, incomplete emissions sources, and other qualitative and quantitative discrepancies that affect the completeness and accuracy of the facility's baseline application.

If material errors are discovered, the Certifying Official must correct these errors before submitting the facility's baseline application. If immaterial errors are discovered, the Certifying Official is encouraged to correct errors; however baseline applications can be verified and submitted with unresolved immaterial errors. More information on materiality is available in section 8.2.7.

The verifier cannot sign off on a facility's baseline application if there are unresolved material discrepancies (discrepancies accounting for greater than five per cent of total emissions).

8.4.1.1 Threat of Advocacy

The Third Party Verifier must remain independent through out the verification. If material or immaterial errors are found in the facility's submission, the Verifier cannot consult or provide advice on possible solutions as this will compromise the Third Party Verifier's independence and could compromise the verification results. Decisions on corrective actions must be left to the Certifying Official.

8.5 Subsequent Events

In certain circumstances, matters may come to the attention of the Third Party Verifier that renders a previously issued Verifier's Report invalid or inaccurate. Third Party Verifiers are not required to actively monitor the validity of their reports after issuance. However, where it is brought to the attention of the Third Party Verifier that a previous statement is no longer accurate, they must notify the Certifying Official. The Certifying Official must notify Alberta Environment to discuss further follow-up actions that may be required.

9.0 Alberta Environment Audit

Alberta Environment has committed to auditing 10 per cent of baseline emissions intensity applications annually. Audits are being undertaken to check the accuracy of the reported information and to flag anomalies. Information will be used to ensure transparency in the Specified Gas Emitters Program and to support an annual program review and assessment.

Immaterial discrepancies flagged by the auditors will be reviewed and addressed on a go forward basis. These issues will be addressed on a case-by-case basis.

Where material errors are identified, Alberta Environment will work with the facility to determine the most appropriate course of action required to address and correct the discrepancy. Where possible, material discrepancies will be addressed on a go forward basis.

9.1 Facility Selection

Alberta Environment uses the following criteria to select facilities for auditing:

- Coverage across sectors;
- A range of facility sizes and complexity;
- New and established facilities;
- A cross-section of verifiers hired to review third party submissions;
- Anomalies or issues encountered during the desktop review; and
- Random selection.

Based on the criteria above, some facilities may be audited more than once or be audited several times in succession to better understand how facility emissions are tracking over time.

9.2 Audit Process

Alberta environment's audit process uses a similar approach to third party verification with a few key differences.

Alberta Environment will conduct an internal review process to determine which facilities will be audited. Alberta Environment will then issue a Request for Proposal. Auditors will be hired based on whether they meet the requirements of a Third Party Verifier; their audit experience; and their sector specific experience. Auditors hired by Alberta Environment must meet the same independence requirements as Third Party Verifiers. An audit team will not be assigned to a facility where there is actual or perceived conflict of interest unless sufficient action can be taken to ensure independence.

Once the auditors have been assigned, Alberta Environment will issue written notice to the facilities indicating they have been selected for audit and who the auditors will be. The auditors will contact the Certifying Official to set up an appropriate audit schedule, and to request supplemental information needed to complete the audit.

Auditors are encouraged to perform a site visit to support the audit. Details of the site visit and audit will be included in the verification plan, which will be shared with the Certifying Official before the site visit.

Auditors may schedule a close out meeting with the Certifying Official to discuss key findings; however, the audit report **must** be submitted directly to Alberta Environment. Alberta Environment will review the audit findings and coordinate a follow-up meeting with the facility to determine what, if any, follow-up action is needed. Alberta Environment will work with facilities to address outstanding issues.

9.3 Audit Methodology

Auditors must use one of the following three audit methodologies consistent with verification methodology requirements:

- ISO 14064 Part 3 – Greenhouse Gases: Specification with guidance for the validation and verification of greenhouse gas assertions
- Standards for Assurance Engagements, Canadian Institute of Chartered Accountants (CICA) Handbook – Assurance Section 5025
- International Standard on Assurance Engagements (ISAE) 3000 - Assurance Engagements Other Than Audits or Reviews of Historical Financial Information

Auditors will select the methodology appropriate to their audit. Methodology used by the auditors may not be the same methodology used by the Third Party Verifier.

9.4 Level of Assurance

Alberta Environment requires all audits be performed to at least a limited level of assurance, consistent with the requirements for Third Party Verification. However, Alberta Environment may request some audits be performed to a more rigorous reasonable level of assurance. Reasonable audits will only be undertaken on facilities where the auditor deems there to be sufficient data management, quality assurance, and access to information to support reasonable assurance.

9.5 Audit Report

Auditors must produce an audit report for each facility that meets the requirements identified in the Third Party Verification Report. This report, including the assurance statement, must be submitted directly to Alberta Environment. Alberta Environment will review the report and contact the facility to discuss the audit findings and determine what, if any, follow-up is needed.

9.6 Continuous Improvement

Alberta Environment is committed to continuous improvement. Alberta Environment will undertake an annual program review of the Specified Gas Emitters Program, particularly during the initial years of the program. Results from the audit will be used to provide input into what areas are working and what areas need adjustments. As such, Alberta Environment has asked its auditors to identify any issues encountered during the audit. This acts as an independent review of the Specified Gas Emitters Program.

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APPENDIX A

Completing the Baseline Application

Baseline Application forms are available in Microsoft Excel format on the Alberta Environment Specified Gas Reducing and Compliance website at:

http://environment.alberta.ca/1167.html

The Baseline Application form contains the following sections:

Section A: Administrative Information
Section B: Emissions, Production and Intensity Information
Section C: Calculation Methods
Section D: Cogeneration Information
Section E: Baseline Calculation
Section F: Additional Comments
Section G: Third Party Verifier Information
Submission of Information
Submission Checklist
Conflict-of-Interest Checklist
Statement of Qualification
Statement of Verification
Statement of Certification

Sections A-G forms must be filled out. If the form is not applicable, the N/A box must be checked. This lets the reviewers know the section is not applicable rather than omitted or over looked. All grey cells are calculated automatically to reduce transcription errors.

The Conflict-of-Interest, Statement of Qualification, Statement of Verification, and Statement of Certification must be printed and signed. **The signed original forms must be submitted to Alberta Environment as part of the facility's baseline emissions intensity application.**

Instructions

This section provides assistance with filling out the application form.

Section A: Administrative Information

Worksheet A1
Section A: Administrative Information

Facility ID Number
Is the facility six digit ID number used by the facility for the one-window electronic reporting program for greenhouse gas emissions. If the facility did not submit using the

EDR for 2004, 2005 or 2006 reporting, it will not have a facility ID. If this is the case, AENV will generate a number for the facility.

Facility Name
This is the legal name for the facility.

EPEA Approval/Registration Number(s)
This is the approval number for the facility operations issued under the Envrionmental Protection and Enhancement Act (EPEA). If the facility does not have an EPEA approval, N/A must be entered in this space.

EUB License/Registration Number(s)
All active EUB license and/or registration numbers applying to this facility must be entered. If the facility does not have an EUB license or registration, enter N/A.

ERCB License/Registration Number(s)
All active ERCB license and/or registration numbers applying to this facility must be entered. If the facility does not have an ERCB license or registration, enter N/A.

NPRI ID(s)
This is the National Pollution Release Inventory number specific to the facility. If the facility does not have an NPRI ID, enter N/A.

NAICS
This is the six-digit North American Industry Classification System number unique to a facility. The Person Responsible should use the NAICS code from their most recent Specified Gas Report submission. Statistics Canada's NAICS search tool is available at: http://www.statcan.ca/english/Subjects/Standard/naics/2002/naics02-menu.htm

Facilities that have more than one operation should select the NAICS code most representative of the business operations and use that number.

Facility Geographical Coordinates
The latitude and longitude coordinates in NAD 83 for the facility's center point must be entered. Geographic coordinates in NAD 27 can be converted to NAD 83 using Natural Resources Canada's online conversion system: http://www.geod.nrcan.gc.ca/apps/ntv2/ntv2_geo_e.php

Pipeline facilities should pick one point or piece of equipment (such as a compressor station) along the contiguous section of the pipeline operation that will be used as the facility's geographical coordinates.

Facility Legal Land Description
Enter the facility's legal land description. Pipeline facilities may enter N/A for their legal land description.

Facility Location including city, district, province, and postal code
This is the physical location of the facility.

Facility Mailing Address
The facility's mailing address may be a head office that differs from the physical location of the facility.

First Year of Commercial Operation
This is the first full year of commercial operation for the facility. If the facility came on stream part-way through a calendar year, the first year of commercial operation would be its first full year of commercial operation.

Describe the criteria used to determine the first and the 2008 year of commercial operation for this facility
Factors to be considered include, but are not limited to, completion of construction, production of output, whether the facility has started receiving feedstock or input, commissioning, the date of operation as stated in the EPEA approval for the facility or other reasonable alternative.

Worksheet A2

Reporter and Reporter contact information
This is the person responsible for the completing the facility's baseline application and is the contact person for the facility for questions pertaining to the Baseline Emissions Intensity Application).

Reporting Company Information
Enter the reporting company's legal and trade names, reporting company's business number, and reporting company mailing address. The legal and trade names may not be the same. The business number is a nine-digit common identification number provided by the Government of Canada. It is usually found on a company's GST form.

Worksheet A3

Description of the facility's boundaries and operations
Provide a description of the facility's boundaries and operations. This should include general information about what the boundaries of the facility are, operations and activities included at the facility, if something is excluded (i.e. power plant - coal from a mine and the emissions associated with the mine are reported by the mine not the power plant) and any other relevant boundary or operational information. If additional space is required, attach an additional document with the submitted Baseline Application, indicating to which section of the Baseline Application the additional information refers.

Worksheet A4

Consultant Information

If a consultant was not hired to complete the Baseline Application, an X must be entered in the appropriate box. If a consultant was hired to compile and complete the baseline application, the contact information for the consultant must be entered in this space.

Worksheet A5
Section A: Administrative Information (continued)

Public Contact
Contact information for the public contact must be entered in this space. This is the person who is responsible for any public enquiries or questions regarding the facility's baseline application. Enter an X if this person is the same as the Reporter.

Certifying Official
Contact information for the Certifying Official must be entered in this space. This is the person with legal authority to sign for the facility. This information will carry forward to the Statement of Certification.

Worksheets A6 and A7

Parent Company Information
Enter an "X" next to each parent company (Canadian company owning 10% or more of the facility) before filling in the required information. Leave the boxes blank if you do not have any additional parent companies.

If the parent company (companies) are from outside Canada, enter all applicable information including contact information and the DUNS (data universal numbering system) number—a nine digit tracking number used by businesses and government to track businesses worldwide.

Section B: Emissions, Production and Intensity Information

Specified Gas emissions (CO_2, CH_4, N_2O, HFC, PFC and SF_6) subject to the *Regulation* are reported by source category and species. This information is used to calculate the total direct emissions (TDE) and total annual emissions (TAE) for the facility. Total annual production information must also be reported. The TAE and production information will be used to calculate the baseline emissions intensity for the facility. The information entered in this section will carry forward throughout the rest of the application.

The application for *established facilities* requires information for the years 2003, 2004 and 2005. The application for *new facilities* requires information for only the third year of commercial operation.

The following applies for the emission fields: if the specified emissions from the specified source do not occur at the facility, enter an "X" in the appropriate N/A box.

Worksheets B1, B1(2) and B1(3)
Section B: Emissions, Production and Intensity Information

More information on each source category is available in section 4.0 of this guidance document. All conversions to CO_2e and other calculations (all grey fields) are completed automatically.

Stationary Fuel Combustion Emissions
Enter CO_2, CH_4 and N_2O emissions in tonnes from stationary fuel combustion sources. This information will be used to automatically calculate CO_2e emissions from stationary fuel combustion.

Note, CO_2 emissions from the combustion of biomass are **not** reported in this source category, there is a separate field in Section B4.

Industrial Process Emissions
Enter CO_2, CH_4 and N_2O emissions in tonnes from industrial process sources. This information will be used to automatically calculate CO_2e from each entry.

Venting Emissions
Enter CO_2, CH_4 and N_2O emissions in tonnes from venting sources. This information will be used to automatically calculate CO_2e from each entry.

Flaring Emissions
Enter CO_2, CH_4 and N_2O emissions in tonnes from flaring sources. This information will be used to automatically calculate CO_2e from each entry.

Other Fugitive Emissions
Enter CO_2, CH_4 and N_2O emissions in tonnes from other fugitive sources. This information will be used to automatically calculate CO_2e from each entry.

On-site Transportation Emissions
Enter CO_2, CH_4 and N_2O emissions in tonnes from on-site transportation sources. This information will be used to automatically calculate CO_2e from each entry.

Waste and Wastewater Emissions
Enter CO_2, CH_4 and N_2O emissions in tonnes from waste and wastewater sources. This information will be used to automatically calculate CO_2e from each entry.

Note, CO_2 emissions from the decomposition of biomass are **not** reported in this source category; there is a separate field in Section B4 for these emissions.

Formation CO_2 Emissions
Enter CO_2 emissions in tonnes from Formation CO_2 sources. This information will be used to automatically calculate CO_2e from each entry.

Worksheets B2, B2(2) and B2(3)
Section B: Emissions, Production and Intensity Information (continued)

Hydrofluorocarbon (HFC) Emissions
Hydrofluorocarbon emissions related to production must be entered in the appropriate categories relative to their emissions source and species.

If these emissions are negligible, please provide a calculation identifying the quantity of emissions relative to overall emissions to support their exclusion.

Worksheets B3, B3(2) and B3(3)
Section B: Emissions, Production and Intensity Information (continued)

Perfluorocarbon (PFC) Emissions
All perfluorocarbon emissions related to production must be entered in the appropriate categories relative to their emissions source and species.

If these emissions are negligible, provide a calculation identifying the quantity of emissions relative to overall emissions to support their exclusion.

Sulphur Hexafluoride (SF_6) Emissions
All sulphur hexafluoride emissions related to production must be entered in the appropriate categories relative to their emissions source.

If these emissions are negligible, provide a calculation identifying the quantity of emissions relative to overall emissions to support their exclusion.

Total HFC, PFC and SF_6 Emissions
Total HFC, PFC and SF_6 emissions in tonnes CO_2e are automatically calculated.

Worksheets B4, B4(2) and B4(3)
Section B: Emissions, Production and Intensity Information (continued)

Note: CO2 emissions from the combustion and decomposition of biomass are not included in the calculation of the TAE and Emissions Intensity for compliance. Non-CO_2 emissions from Biomass combustion and Decomposition must be included in Section B1 in the Stationary fuel Combustion and Waste and Wastewater categories, respectively, and are included in the calculation of the TAE and Emissions Intensity for compliance of the facility.

CO_2 Emissions from the Combustion of Biomass
Enter tonnes of CO_2 emissions from the combustion of biomass materials.

CO_2 Emissions from Decomposition of Biomass
Enter tonnes of CO_2 emissions in tonnes from the decomposition of biomass waste materials in tonnes.

Worksheets B5, B5(2) and B5(3)
Section B: Emissions, Production and Intensity Information (continued)

Total CO_2, CH_4 and N_2O Emissions
The total CO_2, CH_4 and N_2O emissions are all automatically calculated using values already entered in the Baseline Application form.

Total Annual Emissions Calculation
The total direct emissions, GHG emissions from industrial process, CO_2 from biomass and total annual emissions fields are all automatically calculated using values already entered in the Baseline Application form.

Public availability of GHG emissions information
Enter an "X" in the box if the greenhouse gas emissions data is publicly available for the baseline year(s).

Facilities using the Baseline Emissions Intensity Application for New/Established Stand-Alone Cogeneration Facilities will also need to indicate if production information is publicly available.

Worksheets B6, B6(2) and B6(3)
Section B: Emissions, Production and Intensity Information (continued)

These worksheets do not apply to facilities using the Baseline Emissions Intensity Application for New/Established Stand-Alone Cogeneration Facilities.

Production Information
Production values for each end product must be entered using appropriate SI units. This information is used to determine total production at the facility.

Facilities that do not have an end product (i.e. landfills) may use any input, output or other thing specified under subsection (4) of the *Specified Gas Emitters Regulation.*
Enter the total production (P) value and units calculated for the baseline year (combine all applicable production items in an appropriate manner). The default setting is to directly sum all products listed and use the units from the first product listed, but this should be adjusted if a more appropriate combination method exists.

List what is included in total production (P). Facilities that produce multiple products must explain (include formulas) how total production was calculated.
Describe how the production calculations were done.

Public Availability of Production Information
Enter an "X" in the box if the production information is publicly available for the baseline year(s).

Worksheets B7, B7(2) and B7(3)
Section B: Emissions, Production and Intensity Information (continued)

These worksheets do not apply to facilities using the Baseline Emissions Intensity Application for New Facilities or to facilities using the Baseline Emissions Intensity Application for New/Established Stand-Alone Cogeneration Facilities.

Emissions Intensity
The emissions intensity value for the baseline year is automatically calculated using total annual emissions and total production.

Section C: Calculation Methods

This section of the Baseline Application requires:

- Listing of the general category of calculation methodology used for each specified gas by source category;
- Listing of the calculation methodology reference used for each specified gas by source category;
- The description of greenhouse gas emissions estimation and calculation methods and reference materials used in calculating the facility's greenhouse gas emissions;
- The identification of the years a facility previously reported greenhouse gas emissions to Alberta Environment under the *Specified Gas Reporting Program*;
- The reporting of any change in emissions calculation methods between years; and
- The reason why the calculation methods were modified.

Worksheet C1
Section C: Calculation Methods

Method Type
List all the method categories that were used to calculate emissions of each gas by source category.

Enter 1 for monitoring/direct measurement, 2 for intermittent (periodic) direct measurement, 3 for calculated based on measured surrogate parameters, 4 for extrapolated from historical data, 5 for estimated from design requirements, 6 for estimated from agreements, 7 for mole balance with efficiency factors, 8 for equipment-specific emission factors, 9 for manufacturer's emission factors, 10 for models based on surrogate parameters, 11 for generic emission factors and 12 for top-down emission factors.

Worksheet C2
Section C: Calculation Methods (continued)

Citation of Method References
List all the method references that were used to calculate emissions of each gas by source category.

Worksheets C3, C3 (p2), C3 (p3) and C3 (p4)
Section C: Calculation Methods (continued)

Provide details on the method(s) used including the rationale for selection of the specific methods for determining the facility's direct greenhouse gas emissions. Information provided should be sufficiently complete to allow Alberta Environment to understand how calculations were made. Additional information should be included in a separate document if more space is required. **This information must include**:

- emission estimation/calculation methodologies,
- all numerical emission factors used,
- equations,
- example calculations, and
- citation of reference materials

If your facility includes an integrated cogeneration system please also include:

- Explanation of how heat calculations were done, including the enthalpies;
- Various thermal streams and annualized flow averages, temperature averages, and pressure averages for each stream; and
- Simple conceptual/logic diagram of the cogeneration layout.

Consistent methods and reference materials must be used across all baseline years.

Differences in the methods or information used between the 2003, 2004 and 2005 calculations should be noted and a rational for these differences should be provided.

Worksheets C4, C4 (p2), C4 (p3)
Section C: Calculation Methods (continued)

In the space provide, indicate if, and in which years, you have previously reported greenhouse gas emissions to Alberta Environment under the Specified Gas Reporting Program.

If the emissions reported in the Baseline Application differ from the emissions reported previously under the Specified Gas Reporting Program indicate in the space below why and where these differences occur. Also indicate the impact this has had on the reported values (i.e. increased or decreased by X tonnes, etc). By providing the greenhouse gas emissions for the years previously reported in this Baseline Application, you will not be

required to resubmit updated emissions data under the Specified Gas Reporting Program. Alberta Environment will review the submitted data and upon accepting the data will update the data collected under the Specified Gas Reporting Program (where applicable).

Additional information may be included on a separate sheet. Facilities restating 2004, 2005 or 2006 emissions data should contact Environment Canada to determine whether they need to restate their emissions under the National Mandatory Greenhouse Gas Reporting Program.

Section D: Cogeneration Information

Facilities submitting as stand-alone cogeneration or with integrated cogeneration should complete this section.

Worksheets D1, D1(2) and D1(3)
Section D: Cogeneration Information

Cogeneration Information
Enter an "X" in the N/A box if there was no integrated cogeneration unit operational baseline period, or if the facility did not use deemed greenhouse gas emissions for a cogeneration unit in the Baseline Emissions Intensity Application. This section of the worksheet is then complete.

Facilities using the Baseline Emissions Intensity Application Form for New/Established Stand-Alone Cogeneration facilities should follow the steps below.

GHG Emissions (Cogen)
Enter the *total greenhouse gas emissions* in tonnes CO_2e from the cogeneration unit.

Fuel Use Information
Enter the *type*, *quantity*, *units* and *percent mixture* of the fuels used by the cogeneration unit.

Heat
Enter the *total heat production from cogeneration* (H) in GJ. *Deemed input energy attributed to heat* (E_H) in GJ is automatically calculated. Enter the *mass/volume of fuel deemed used to produce heat* (M_H) in the appropriate units. Enter the *deemed greenhouse gas emissions from heat production* (D_H) in tonnes CO_2e.

Operations
Enter the *Total Hours of Operation of the Cogeneration Facility* in hours.

Electricity
Enter the *total electricity generation* (E) in MWh. *Deemed greenhouse gas emissions from electricity generation* (D_E) in tonnes CO_2e is automatically calculated. Facilities

using the Baseline Emissions Intensity Application Form for Stand-Alone Cogeneration Facilities will also have the *intensity metric for cogeneration electricity* (I_E) in tonnes CO_2e / MWh automatically calculated.

Adjustments
The *total cogeneration baseline adjustment* (A_T) is automatically calculated.

Worksheets D2, D2(2) and D2(3)
Section D: Cogeneration Information (continued)

If fuel factors were used to calculate greenhouse gas emissions from cogeneration, provide the factors used with references.
Enter the required information. If fuel factors were not used simply enter "not applicable".

If fuel analysis was used to calculate greenhouse gas emissions from cogeneration, provide a synopsis of the fuel analysis.
Enter the required information. If fuel analysis was not used simply enter "not applicable".

Section E: Baseline Calculation

The facility baseline emissions intensity is calculated based on the emissions, cogen and production information already entered in the Baseline Application.

Worksheet E
Section E: Baseline Calculation

Baseline Emissions Intensity

For facilities using the Baseline Emissions Intensity Application Form for New/ Established Facilities:
Emissions (TAE) and production (P) information are used to automatically calculate the baseline emissions intensity (BEI). Facilities that completed section D (cogeneration information) will have their deemed greenhouse gas emissions from heat (D_H) applied to the total annual emissions (less emissions from the cogeneration unit).

For facilities using the Baseline Emissions Intensity Application Form for New/ Established Stand-alone Cogeneration Facilities:
Deemed greenhouse gas emissions attributed to heat (D_H) and total heat produced by the cogeneration facility (H) are used to automatically calculate the baseline emissions intensity (BEI).

Section F: Additional Comments

This section of the Baseline Application can be used to provide additional information required to support the Baseline Application.

Worksheet F
Section F: Additional Comments

Facility or Company Website
If available, enter the website of the facility or reporting company.

Comments
Enter any additional comments or information that is relevant to the Baseline Application.

Note: Power plant facilities are required to report gross electricity generation in the additional comment field.

Section G: Third Party Verifier Information

This section addresses the qualifications of the Third Party Verifier and provides information on the verification process. The information entered in this section will carry forward to the Conflict-of-Interest Checklist, Statement of Qualification and Statement of Verification.

Worksheet G
Section G: Third Party Verifier Information

Third Party Verifier Information
Provide contact information for the Third Party Verifier.

Verification Company Information
Provide contact information for the company undertaking the Third Party Verification.

Verifier Qualifications
Explain how the Verifier satisfies the Qualification requirements for Third Party Verifiers.

Baseline Emissions Intensity Application Form Submission Information

This section guidance on the submission process for the Baseline Application.

Facilities requesting confidentiality **must submit a written request** to the Director with appropriate justification and supporting documentation by the June 1 baseline application

deadline. Additional information on confidentiality is available in section 7.0 of this document.

It is an offence under the *Climate Change and Emissions Management Act* to provide false or misleading information. Maximum penalties upon conviction are significant and can include, in the case of knowingly providing false or misleading information, imprisonment: see sections 44 and 45 of the *Climate Change and Emissions Management Act*.

Submission Checklist

This Checklist is to be used prior to submission to ensure all required supporting documentation has been provided. Enter 'X' in the field as each component of the submission is compiled. Enter the file names of any supporting documentation included.

Conflict-of-Interest Checklist

The Third Party Verifier must complete a Conflict-of-Interest Checklist to confirm their independence from the facility or reporting company. If any of the statements are marked true, the verifier must provide documentation of how the potential conflict of interest will be managed. If the potential conflict-of-interest is a sufficient perceived or actual threat to impartiality and cannot be effectively managed, Alberta Environment will not be able to accept a Third Party Verifier's Report from that verifier for that facility.

A signed original Conflict-of-Interest Checklist must be submitted to Alberta Environment.

Statement of Qualification

The Statement of Qualification (SoQ) states that the Verifier meets or exceeds the qualifications of Third Party Verifiers as stated in section 18 of the *Regulation*, and this *Technical Guidance Document for 2008 Specified Gas Compliance Reports*.

A signed original SoQ must be submitted to Alberta Environment.

Statement of Verification

The Statement of Verification (SoV) requires the Third Party Verifier to:

- Describe the objective of the review and the entity or portion thereof, the subject matter and the time period covered by the review,
- Identify the GHG assertion (core numerical assertions from the application are carried forward automatically),
- Describe the responsibilities of management and the reviewer,

- Identify the applicable standards in accordance with which the review was conducted,
- Identify the criteria against which the GHG assertion and supporting evidence was evaluated,
- State a conclusion that conveys the level of assurance being provided and/or any reservation the Third Party Verifier may have,
- State the date of the report
- Identify the name of the lead verifier (and firm)

A signed original SoV must be submitted to Alberta Environment.

Statement of Certification

The Statement of Certification (SoC) requires the designated Certifying Official of the facility to certify that they have reviewed the Compliance Report and have exercised due diligence to ensure that the submitted data and information are true and complete, and the values and information throughout the Application are accurate, based on reasonable estimates using available data and information.

A signed original SoC must be submitted to Alberta Environment.

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